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SOAH DOCKET NO. 473-21-0538
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APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES	§ § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO SIERRA CLUB'S SECOND SET OF REQUESTS FOR INFORMATION

MARCH 11, 2021

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO SIERRA CLUB'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. SC 2-1:

For each of the Company's coal or solid-fuel units (Dolet Hills, Flint Creek, Pirkey, Turk, and Welsh), please identify the amount of money that SWEPCO included in the Company's test year spending as proposed in this case for capital expenditures during the test year.

Response No. SC 2-1:

See the Company's supplemental response to CARD 1-16.

Prepared By: Tara D. Beske	Title: Regulatory Consultant Staff
Sponsored By: Monte A. McMahon	Title: VP Generating Assets SWEPCO

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO SIERRA CLUB'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. SC 2-2:

Refer to SWEPCO's response to Sierra Club 1-5, Attachment 6 and the CCR and ELG retrofits analysis.

a. Indicate which modeling software was used to conduct the analysis.
b. Provide all workbooks, with formulas intact, used to develop the results shown in Attachment 6.
c. Provide a list of all capital expenditures associated with CCR and ELG compliance included in each of the six modeled scenarios for each unit and provide the cost of each.
d. Provide the following forecasts utilized for this analysis:
    i. EIA commodity price forecasts (with and without CO2 price)
    ii. SPP market price forecasts (with and without CO2 price)
    iii. CO2 price forecasts
e. Explain why the Company used the EIA commodity price forecasts instead of AEP's own forecasts.
f. Provide each the following inputs for each unit, both new and existing, modeled at the highest level of granularity used in conducting the retrofit analysis:
    i. Coal price ($/MMBtu)
    ii. Natural Gas price ($/MMBtu)
    iii. Heat rate for each unit (Btu)
    iv. Capital expenditures ($)
    v. Variable Operation and Maintenance ($/MWh)
    vi. Fixed Operation and Maintenance ($/MW)
g. For each replacement resource available to the model, provide each of the following inputs for each resource at the highest level of granularity used in conducting the retrofit analysis:
    i. Replacement resource options
    ii. Replacement resource size (MW)
    iii. Year replacement resource is available (year)
    iv. Cost of replacement resource option ($/MW)
    v. Annual capacity factor
h. Provide the following outputs by unit:
    i. Annual generation (MWh)
    ii. Fuel costs ($)
    iii. VOM costs ($)
    iv. FOM costs ($)
    v. Capital expenditures for ELG and CCR environmental compliance ($)
    vi. Other capital expenditures ($)
    vii. Energy and ancillary market revenues ($)

i. Explain the End Effects assumptions and methodology used.
j. Provide the discount rate used.

Response No. SC 2-2:

a. The modeling software used to conduct the CCR/ELG retrofit analysis was Plexos developed by Energy Exemplar.
b. Please see SC 2-2 HS Attachments 1 through 11 for the workbooks used to develop the results shown in SC 1-5 Attachment 6.
c. Please see SC 2-2 HS Attachment 12 for all capital expenditures associated with CCR and ELG compliance included in each of the six modeled scenarios for each unit and provide the cost of each.
d. Please see the supplemental response to CARD 2-10 for the commodity prices forecasts used in the analysis.
e. The EIA's Annual Energy Outlook (AEO) is a widely recognized, readily accessible and fee-free resource for long-term energy market projections. It is also well understood that the AEO is based upon the assumption regulations remain unchanged and long-term energy projections lack certain RTO-level granularity. As such, AEPSC utilized the Aurora energy market simulation model to produce the Companies' EIA-Based Fundamentals Forecast based upon EIA inputs to serve as a reference point against which ratepayer benefits may be compared and assessed.
f. Please see SC 2-2 HS Attachment 13 for new and existing unit information used in the analysis.
g. Please see SC 1-8 and SC 2-2 HS Attachment 14 for replacement resource inputs used in the analysis.
h. Please see SC 1-8 for Generation, VOM, and FO&M. See also SC 2-2 HS Attachment 15 for outputs by unit from the analysis.
i. The End-Effects period takes into account the costs of those new resource additions after the end of the planning period. The infinite end-effects period was selected to allow the model to capture the long-run costs of resource additions made near the end of the Planning Period.
j. The discount rate used in the analysis was 6.98%

The attachments responsive to this request are HIGHLY SENSITIVE MATERIAL under the terms of the Protective Order. Due to current restrictions associated with COVID-19, this information is being provided electronically and a secure login to access the information will be provided upon request to individuals who have signed the Protective Order Certification.

Prepared By: Mark A. Becker	Title: Mng Dir Res Plnning&Op Anlysis
Prepared By: Joseph S. Perez	Title: Forecast Analyst Prin
Sponsored By: Thomas P. Brice	Title: VP Regulatory & Finance
Sponsored By: Monte A. McMahon	Title: VP Generating Assets SWEPCO

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO SIERRA CLUB'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. SC 2-3:

Refer to SWEPCO response to Sierra Club 1-9(d) regarding the description of the projects that the Company intends to undertake and the costs that will be incurred to comply with ELG and CCR requirements for the Flint Creek coal unit. For each step or item described under the Dry Ash Handling System and the Pond Closure by Removal and construction of new Coal Pile Runoff Pond projects, indicate the following:

a. Whether the step or item is required if the plant retires prior to October 17, 2028.
b. Whether the step or item is required if the plant retires prior to December 31, 2028.
c. The cost of each step or item.

Response No. SC 2-3:

a. - b. The first three bulleted items in SC 1-9 (d) under "Pond Closure by Removal of new Coal Pile Runoff Pond (CPRP)" are required whether Flint Creek retires prior to October 17, 2028 or prior to December 31, 2028. The remaining items are tied to compliance with ELG and CCR requirements impacting operation of the unit beyond these time frames and would not be required.
c. The Company does not maintain project estimates at the bulleted item level provided in its response to SC 1-9 part d. The following reflects the cost estimates maintained by the Company, for the project elements provided by the Company in SC 1-9 part d:

- Dry Ash Handling Systems: $26.7 million
- Pond Closure by Removal and construction of new Coal Pile Runoff Pond: $26.8 million
    - Pond Closure: $17.6 million
    - Pond Repurpose: $9.2 million

Prepared By: Tara D. Beske Title: Regulatory Consultant Staff

Sponsored By: Monte A. McMahon Title: VP Generating Assets SWEPCO

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO SIERRA CLUB'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. SC 2-4:

Refer to SWEPCO response to Sierra Club 1-17 regarding SWECO's investment in the Oxbow Mine lignite reserves.

a. Explain which specific assets or operations are covered by SWEPCO's investment in the Oxbow Mine and therefore are included in rate base.
b. Explain which specific assets or operations are covered by the undepreciated balance related to DHLC and therefore are not included in rate base.
c. Indicate whether SWEPCO receives a rate or return on its investment in the Oxbow Mine.

Response No. SC 2-4:

a. Oxbow Lignite Company ("OLC") assets include mineral rights, land, right of way costs and advance royalties. Since SWEPCO owns 50% of OLC, SWEPCO's equity investment associated with these assets is included in rate base. No return component is included in OLC's lignite bill to SWEPCO.
b. DHLC assets include mining equipment (both leased and owned), buildings, lignite delivery assets and Asset Retirement Obligation asset. These assets are not include in rate base because DHLC builds a return component in its lignite bills which covers DHLC's investment in those assets. SWEPCO records the return component in non-eligible fuel cost for the Dolet Hills Power Station. See direct testimony of Mr. Michael A. Baird pages 35-37 where this DHLC equity return component is included in cost of service as Account 501 non-eligible fuel costs.
c. Yes, SWEPCO receives a return on its equity investment in OLC since the investment is included in rate base in proforma adjustment at WP B-1.5.14.

Prepared By: Michael A. Baird Title: Mng Dir Acctng Policy & Rsrch

Sponsored By: Michael A. Baird Title: Mng Dir Acctng Policy & Rsrch

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO SIERRA CLUB'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. SC 2-5:

Refer to SWEPCO workpaper H-5.2b regarding Fossil Generation Plant additions greater than 100K. Indicate which generation unit(s) are associated with each project.

Response No. SC 2-5:

See Sierra Club 2-5 Attachment 1 for the location of projects listed in Schedule H-5.2b. For those that do not list a specific generating unit, the project includes costs for multiple units.

Prepared By: Tara D. Beske | Title: Regulatory Consultant Staff

Sponsored By: Monte A. McMahon | Title: VP Generating Assets SWEPCO

Schedule H-5.2b Projects by Location		
Funding Project Number	Funding Project Description	Location
000021554	SWEPCO DHLC/Pirkey Land Acq	Dolet Hills Unit 1
000021554	SWEPCO DHLC/Pirkey Land Acq	Pirkey Unit 1
000021701	FC U1 NOx Mods	Flint Creek Unit 1
ARCFLA168	Arc Flash Protectn Swi SWEPCO	Flint Creek Unit 1
ARCFLA168	Arc Flash Protectn Swi SWEPCO	Knox Lee Generating Plant
ARCFLA168	Arc Flash Protectn Swi SWEPCO	Lone Star Generating Plant
ARCFLA168	Arc Flash Protectn Swi SWEPCO	Mattison Generating Plant
ARCFLA168	Arc Flash Protectn Swi SWEPCO	Pirkey Unit 1
ARCFLA168	Arc Flash Protectn Swi SWEPCO	Turk Unit 1
ARCFLA168	Arc Flash Protectn Swi SWEPCO	Wilkes Generating Plant
ARS6ACWPR	CIRC WATER PUMP REPLACE	Arsenal Hill 6A
ARS6ASCRR	Stall U6A SCR Catalyst Replace	Arsenal Hill 6A
ARS6BCWPR	CIRC WATR PUMP REPLACE Unit 6B	Arsenal Hill 6B
ARS6BSCRR	Stall U6B SCR Catalyst Replace	Arsenal Hill 6B
ARS6STMAJ	STEAM TURBINE MAJOR - 6	Arsenal Hill 6S
ARSBAYOU1	Stall-Bayou Bank Stabilization	Stall Generating Plant
ARSCP6A17	STALL 6A LTSA CAPITAL 2017	Arsenal Hill 6A
ARSCP6B18	STALL 6B LTSA CAPITAL 2018	Arsenal Hill 6B
DLHCI0034	DLH Switchgear Replc	Dolet Hills Unit 1
DLHCI0043	DHPS-Upgrade Air Heaters	Dolet Hills Unit 1
DLHCI0044	Rpl Boiler Furnace Lwr Tubing	Dolet Hills Unit 1
FC001FGD0	FC U1 DFGD w/ FF	Flint Creek Unit 1
FC001LNDF	Flint Creek FGD LandFill	Flint Creek Unit 1
FCLEACHAT	FC Landfill Leachate Treatment	Flint Creek Unit 1
FLC090004	Replace Turbine Blade Rows	Flint Creek Unit 1
FLCSTATOR	FLC Spare Stator Bars	Flint Creek Unit 1
FLCU10155	FLC U1B 4-kV Switchgear Repl	Flint Creek Unit 1
FLCU10156	FLC U1C 4-kV Switchgear Repl	Flint Creek Unit 1
FLCU10157	FLC 4KV CH1A1B Switchgear Rpl	Flint Creek Unit 1
IT1681321	Regulated RTU Project - SWEPCO	Flint Creek Unit 1
IT1681321	Regulated RTU Project - SWEPCO	Knox Lee Generating Plant
IT1681321	Regulated RTU Project - SWEPCO	Lieberman Generating Plant
IT1681321	Regulated RTU Project - SWEPCO	Lone Star Generating Plant
IT1681321	Regulated RTU Project - SWEPCO	Welsh Generating Plant
IT1681421	Maximo Imp - SEP - G	Capitalized Software - SEP
IT168BILL	Corp Prgrm Billing - SWEPCO Ge	Capitalized Software - SEP
KXL5CT001	KXL U5 Turbine Bucket Rep	Knox Lee Unit 5
LBM10C008	Lieberman U4 Retube Condenser	Lieberman Unit 4
NRCPSWPCO	NERC CIP SWEPCO	Arsenal Hill Generating Plant
NRCPSWPCO	NERC CIP SWEPCO	Flint Creek Unit 1
NRCPSWPCO	NERC CIP SWEPCO	Knox Lee Generating Plant
NRCPSWPCO	NERC CIP SWEPCO	Lieberman Generating Plant
NRCPSWPCO	NERC CIP SWEPCO	Mattison Generating Plant
NRCPSWPCO	NERC CIP SWEPCO	Pirkey Unit 1
NRCPSWPCO	NERC CIP SWEPCO	Turk Unit 1
NRCPSWPCO	NERC CIP SWEPCO	Welsh Generating Plant
NRCPSWPCO	NERC CIP SWEPCO	Wilkes Generating Plant
NRXSWEPCO	SWEPCO Plant NRX System Deploy	Flint Creek Unit 1

Schedule H-5.2b Projects by Location		
Funding Project Number	**Funding Project Description**	**Location**
NRXSWEPCO	SWEPCO Plant NRX System Deploy	Welsh Generating Plant
PRK12C704	PRK Controls BMS CC	Pirkey Unit 1
PRKCBLR52	OFA CORROSION	Pirkey Unit 1
PRKCFGD60	FGD CONTROLS UPGRADE	Pirkey Unit 1
PRKXENV02	PRK Landfill 2012 thru 2016	Pirkey Unit 1
PRKXWTR53	Replace Pirkey U1 F HP Heater	Pirkey Unit 1
TKARCFLSH	Turk Arc Flash Safety Systems	Turk Unit 1
TRK1PJIFF	Pulse Jet Fabric Filter Rplce	Turk Unit 1
TRK1SCR4L	SCR Catalyst 4th Layer	Turk Unit 1
TRK2LNDFL	TRK ACTIVATE 2 LANDFILL	Turk Unit 1
TRKH20PON	TRK MAKEUP H2O POND	Turk Unit 1
TRKPONDRO	Coal Yard Runoff Surge Tanks	Turk Unit 1
TRKRAILR1	Turk Rail Replacement	Turk Unit 1
TRKRAILR2	Turk Rail Replacement	Turk Unit 1
WLKCI1002	WLK1 HPRHLP TURBINE OVERHAUL	Wlkes Unit 1
WLKCI1004	WLK1 TSI Replacement	Wlkes Unit 1
WLKCI2004	U2 SHRH Outlet BNKHDR Repl	Wilkes Unit 2
WLKCI3004	U3 SHRH Outlet BNKHDR Replc	Wilkes Unit 3
WLKCI3007	Wilkes U3 RETUBE E FW HTR	Wilkes Unit 3
WLKCI3011	RETUBE WILKES U3 F HP HEATER	Wilkes Unit 3
WSHCU0019	WSH U0 Coal Car Dumper Replace	Welsh Unit 0
WSHCU0112	WSH U0 COAL HANDLING 4KV REPL	Welsh Unit 0
WSHCU0CBK	WSH CAP BANK 4KV Switchgr Rpl	Welsh Unit 0
WSHCU1059	WSH U1 AH Bask Interm Hot End	Welsh Unit 1
WSHCU1103	WSH U1 GSU TRANFORMER REPLACE	Welsh Unit 1
WSHCU1105	WSH U1 GENERATOR SPARE COILS	Welsh Unit 1
WSHCU3059	WSH U3 AH Bask Interm Hot End	Welsh Unit 3
WSHCU3101	WSH U3 REPL A C 4KV SWITCHGE	Welsh Unit 3
WSHCU3102	WSH U3B 4-kV Switchgear Repl	Welsh Unit 3
WSHENVENG	WSH U0 ACI / FF / Chimney	Welsh Unit 0
WWSHPPBNB	WSH Capital Non-Budgeted	Welsh Generating Plant PPB Blanket
X00000010	WS-CI-SEPCo-G PPB	WS-CI-SEPCo-G PPB - Blanket Project
X00000124	SS-CI-SEPCo-G GEN PLT	SS-CI-SEPCo-G GEN PLT - Blanket Project (Multiple Locations)
X00000581	SS-CI-SEPCo-G Software	SS-CI-SEPCo-G Software - Blanket Project (Multiple Locations)
ARO	Asset Retirement Obligation	Asset Retirement Obligation - All SWEPCO Plants

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Question No. SC 2-6:

For each of the Company's solid-fuel units (Dolet Hills, Flint Creek, Pirkey, Turk, and Welsh), provide the following information about future planned capital expenditures.

a. Provide a forecast of annual capital expenditures for each generation unit over the next ten years.
b. Provide a specific accounting of all projects and capital expenditures already scheduled or planned at SWEPCO's solid fuel units (coal and lignite) over the next ten years.

Response No. SC 2-6:

a. See Sierra Club 2-6 Highly Sensitive Attachment 1 for a 10-year capital forecast of capital expenditures by plant. Forecasts are not maintained at the unit level.

b. See Sierra Club 2-6 Highly Sensitive Attachment 2 for a 10-year forecast of capital expenditures by project.

Company budget forecasts are updated annually. The capital forecast included in Highly Sensitive Confidential Attachments 1 and 2 does not reflect the Company's announcement to retire the Dolet Hills and Pirkey Plants in 2021 and 2023, respectively, or that the Welsh Plant will cease using coal in 2028.

The attachments responsive to this request are HIGHLY SENSITIVE MATERIAL under the terms of the Protective Order. Due to current restrictions associated with COVID-19, this information is being provided electronically and a secure login to access the information will be provided upon request to individuals who have signed the Protective Order Certification.

Prepared By: Tara D. Beske	Title: Regulatory Consultant Staff
Sponsored By: Monte A. McMahon	Title: VP Generating Assets SWEPCO

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO SIERRA CLUB'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. SC 2-7:

Refer to SWEPCO Schedule H-5.2b and H-5.3b.

a. Indicate whether these costs are all included in the plant in service totals by plant.
b. Explain why the amounts listed here on schedule H-5.3b differ from annual plant additions for accounts 310 – 317 as reported in the prior rate case.
c. Indicate whether any of the projects listed on schedule H-5.3b are included in the total SWEPCO share of Flint Creek CCR/ELG costs total provided in SC 1-9, Attachment 1. If yes, identify all projects that are included in the total from SC 1-9, Attachment 1.

Response No. SC 2-7:

a. Capital expenditures (construction work in progress) are recorded as costs are incurred. Capital additions reflect the cost of a capital investment, once it becomes used and useful and is placed into service. If a capital investment is placed in service during the same period capital expenditures are being reported, then yes the expenditures are included in the cost of a capital addition.

b. As described in part a, capital expenditures (construction work in progress) and capital additions do not always include the same costs, depending on the status of the investment. Capital expenditures in the current base case reflect a different snapshot in time and may not be the same as the costs reported as capital additions in the Company's prior base case. Additionally, once an investment is used and useful and designated as a capital addition, expenditures can continue for a period of time before a project is closed out. For example, an environmental retrofit project can go into service and be reflected as a capital addition; however, activities such as system tuning, finalizing field drawings, and contractor demobilization will continue for a period of time and increase the overall cost of the capital addition.

c. Schedule H-5.3b project "000020379 FLC U1 DBA Conver (CCR/ELG)" is included in the total SWEPCO share of the Flint Creek CCR/ELG cost provided in SC 1-9, Attachment 1.

Prepared By: Tara D. Beske — Title: Regulatory Consultant Staff

Sponsored By: Monte A. McMahon — Title: VP Generating Assets SWEPCO

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO SIERRA CLUB'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. SC 2-8:

Provide total company plant in service amounts from 2015 through present by plant account for each month. For each month, include plant balance as of first day of the month, addition, transfers, retirements, and plant balance at the end of the month.

Response No. SC 2-8:

Please see Sierra Club 2-8 Attachment 1.pdf.

Prepared By: Jason A. Cash	Title: Accounting Sr Mgr
Sponsored By: Jason A. Cash	Title: Accounting Sr Mgr

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO SIERRA CLUB'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. SC 2-9:

Refer to Schedule H-12.2 H-12.2a and 12.2a1 H-12.2b and 12.2b1 (Production data). Update this schedule with generation data for the months of April – December of 2020.

Response No. SC 2-9:

Please see Sierra Club 2-9 Attachment 1 for the updated schedule.

Prepared By: Scott E. Mertz Title: Regulatory Consultant Staff

Sponsored By: Scott E. Mertz Title: Regulatory Consultant Staff

			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
			MWh PRODUCTION BY UNIT										
Line No	Year	Month	AH5	KL2	KL3	KL4	KL5	LIEB1	LIEB2	LIEB3	LIEB4	LS1	MAT1
1	2016	Jul	7 932	1 243	1 467	4 180	21 839	0	-	2,412	8 165	2 210	3 728
2		Aug	4 447	579	346	2 075	24 517	0	328	2,759	4 101	1 117	3 662
3		Sep	3 285	317	-	1 163	27 551	0	352	-	1 872	568	2,062
4		Oct	4 194	311	-	2 269	32 676	0	914	5,024	8 582	1 644	-
5		Nov	-	406	406	974	1 294	0	312	-	4 820	484	-
6		Dec	955	264	-	-	4 782	0	330	-	-	-	-
7	July - December 2016		20,812	3,120	2,219	10,661	112,659	-	2,235	10,194	27,541	6,024	9,452
8	2017	Jan	-	-	-	69	3 218	-	-	-	-	-	-
9		Feb	-	-	-	-	-	-	-	-	-	-	-
10		Mar	-	-	-	-	-	-	-	-	-	-	-
11		Apr	3 806	-	-	2 088	-	-	-	-	1 257	-	-
12		May	-	-	-	-	-	-	-	-	-	-	-
13		Jun	3 548	-	-	-	5 854	-	-	2 576	-	-	-
14		Jul	2 956	511	469	989	24 881	-	388	3,982	3 292	-	2 646
15		Aug	-	-	-	-	-	-	-	-	-	1 131	1,801
16		Sep	868	-	-	815	5 768	-	-	994	1 019	-	81
17		Oct	964	300	336	1 040	5 553	-	-	1 214	2,178	-	1 818
18		Nov	12 463	-	-	-	-	-	-	7,891	10 221	-	-
19		Dec	-	-	-	-	-	-	-	-	-	-	49
20	Total 2017		24,607	811	804	5,002	45,274	-	388	16,658	17,967	1,131	6,395
21	2018	Jan	2 949	569	223	-	21,864	-	365	1,513	4,279	583	1 394
22		Feb	-	-	-	-	-	-	-	-	-	-	-
23		Mar	-	-	-	-	2 794	-	-	-	-	-	-
24		Apr	3 221	281	-	-	2,111	-	649	2,873	4 453	1	1 910
25		May	5 506	-	-	-	41 799	-	1 280	10 914	4 513	1 897	2 330
26		Jun	2 497	247	-	-	20,256	-	-	3 491	1 292	708	-
27		Jul	4 752	1 013	953	-	26,058	-	1 035	5,402	5 949	2 001	2 786
28		Aug	2 254	337	-	-	13 797	-	356	6 178	4 330	-	1,109
29		Sep	2 614	-	-	-	-	-	-	-	-	-	244
30		Oct	-	418	-	-	-	-	-	-	552	-	-
31		Nov	1 733	973	459	-	3 015	-	567	-	6 718	728	2 156
32		Dec	-	-	-	-	5,688	-	-	23	-	-	
33	Total 2018		25,526	3,839	1,635	-	137,382	-	4,252	30,394	32,086	5,918	11,929
34	2019	Jan	4 308	-	-	-	2,240	-	-	-	-		1 671
35		Feb	-	-	-	-	7 542	-	-	-	-	-	552

Sponsored by Naim Hakimi

			(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
			MWh PRODUCTION BY UNIT									
Line No	Year	Month	MAT2	MAT3	MAT4	StallA	StallB	StallS	WKL1	WKL2	WKL3	PRK1
1	2016	Jul	2 890	777	34	105 741	105 060	131,955	28 728	54,051	-	445 083
2		Aug	3 929	660	604	104 468	103 976	131 063	32 191	49 836	-	413 460
3		Sep	2,140	3 244	3,218	94,442	94 579	122 050	5 555	37,628	-	453,734
4		Oct	1 122	-	1 106	68	24	82	17 929	-	-	425,799
5		Nov	684	-	688	85 456	83 620	100 255	32 391	-	-	148 655
6		Dec	-	-		84,428	83,358	100 816	30 169	-	-	474,660
7	July - December 2016		10,766	4,681	5,650	474,603	470,617	586,221	146,962	141,514	-	2,361,392
8	2017	Jan	-	-	-	79 608	58 481	84 616	28 335	-	-	463 953
9		Feb	-	-	-	59 475	58 195	74 449	26,285	-	-	394 070
10		Mar	-	-	-	84 764	85 069	108 112	31,328	-	-	349 699
11		Apr	-	-	-	65 464	65 469	83 154	27 347	-	-	-
12		May	1 870	-	-	88 229	88 845	115 012	30 996	-	7 414	193 964
13		Jun	1 853	2 707	5 388	91 251	91 535	118,507	26 309	13 701	2 456	302 206
14		Jul	653	4 055	4 364	97 624	97,664	125,225	30,936	16,705	30,887	394,314
15		Aug	1 781	2 087	2 255	95 539	95 438	120 901	25 942	3 093	7 820	464 187
16		Sep	-	1 021	3 755	77 745	78 684	101 591	12 648	21 177	17 416	417 748
17		Oct	1 845	1 827	1 844	83 268	83 925	107,113	-	28,232	14 061	329 486
18		Nov	-	1 081	4 757	0	0	0	648	2 625	-	439 787
19		Dec	-	58	1 029	61,763	79 453	78 777	20 009	4,609	3 651	445 332
20	Total 2017		8,002	12,834	23,391	884,731	882,759	1,117,456	260,784	90,143	83,705	4,194,746
21	2018	Jan	1 376	-	1,312	95 332	94,574	109,699	20,255	18,569	-	453 947
22		Feb	-	-		80,210	79,834	93,607	28,754	-	-	383,357
23		Mar	-	-	-	88,748	86 850	104 843	17 168	-	3,026	438 400
24		Apr	1 923	-	-	63 260	62 188	75 011	33,568	-	13 182	118 156
25		May	4,750	2 610	2 525	87,740	89 176	111,491	22,682	-	3 573	453,634
26		Jun	-	1 820	1 829	95 100	92 434	121 019	-	30 341	41 437	437 269
27		Jul	2 199	2 071	2 512	102 733	85 856	119 280	24 011	43 723	59 282	383,047
28		Aug	1,376	840	1 338	92 553	88 788	116,684	26,226	18,178	12,319	464,579
29		Sep	322	-	-	66 693	63 784	84 854	15 754	7 038	9 667	445,140
30		Oct	-	552	-	16 459	15 936	20,749	11 728	13 793	10 835	333 999
31		Nov	2 784	2 437	2 450	21 710	13,997	19,767	17 519	15 445	20,529	294 796
32		Dec	-	-	-	36 523	36,924	42 725	19 122	13,720	2 119	271 382
33	Total 2018		14,730	10,329	11,965	847,059	810,342	1,019,730	236,789	160,807	175,969	4,477,706
34	2019	Jan	2 680	-	-	58 273	60 055	69 615	23 696	5,551	3 731	468 452
35		Feb	1 136	-	-	72 874	72 656	84 787	25,201	3 559	3 614	342 501

			(22)	(23)	(24)	(25)	(26)	(27)	(28)
			MWh PRODUCTION BY UNIT						
Line No	Year	Month	DH1	WSH1	WSH2	WSH3	FC	TK	Sub Total
1	2016	Jul	205 163	259 693	-	224,041	140,866	220,012	1,977,271
2		Aug	187 637	251 133	-	263 565	162 879	239 110	1,988,442
3		Sep	127,621	258 211	-	225,677	169 614	239 756	1,874,641
4		Oct	90 105	311 609	-	92 226	69,648	251 883	1,317,212
5		Nov	48,501	70 579	-	245 706	75 272	179 052	1,079,554
6		Dec	114,415	249,205	-	333 461	164 501	165,196	1,806,538
7	July - December 2016		773,442	1,400,429	-	1,384,676	782,780	1,295,009	10,043,658
8	2017	Jan	149 598	305 004	-	294 948	143 396	243 669	1,854,895
9		Feb	108,302	197 466	-	240 447	131 002	214,370	1,504,061
10		Mar	27 602	283 065	-	18,050	158 417	240 906	1,387,013
11		Apr	70 676	316 865	-	75 978	107 873	236 799	1,056,777
12		May	186,918	281 479	-	194 172	-	130 455	1,319,355
13		Jun	183 751	276 773	-	249 782	50 101	232 985	1,661,283
14		Jul	128 634	323 399	-	318,814	151 859	253 038	2,018,286
15		Aug	55 258	283 228	-	298 575	159 451	239 930	1,858,418
16		Sep	-	300 625	-	69,171	116 906	234 249	1,462,281
17		Oct	-	65 616	-	73 172	119 485	225 784	1,149,060
18		Nov	-	239 587	-	290,686	126 738	221 673	1,358,158
19		Dec		297 527	-	288 345	126,145	232 849	1,639,596
20	Total 2017		910,739	3,170,633	-	2,412,139	1,391,373	2,706,707	18,269,182
21	2018	Jan	83 285	269 420	-	261 217	150,729	228,980	1,822,431
22		Feb	69 983	206 719	-	97 059	120 203	206 590	1,366,317
23		Mar	-	201 343	-	125,282	4,832	224,406	1,297,693
24		Apr		169 723	-	232 927	-	209 365	994,804
25		May	18 568	46 751	-	251 070	64,019	39 505	1,266,335
26		Jun	85 190	225 938	-	255 539	130,802	218,318	1,765,526
27		Jul	80 975	273,844	-	269 760	133,815	237 384	1,870,441
28		Aug	86,768	264 057	-	259 032	138,754	241 033	1,840,887
29		Sep	87 508	228 128	-	227 290	119 885	197 733	1,556,656
30		Oct	56 312	309 230	-	119 768	93 236	199 200	1,202,767
31		Nov	-	312 248	-	218 926	162,375	254 898	1,376,228
32		Dec		318,319	-	313,278	164 237	246,329	1,470,388
33	Total 2018		568,589	2,825,721	-	2,631,149	1,282,887	2,503,742	17,830,474
34	2019	Jan	-	268,403	-	260 490	159,300	235 402	1,623,867
35		Feb	-	163 749	-	217 973	139 048	217 464	1,352,657

Sponsored by. Naım Hakımı

			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
			MWh PRODUCTION BY UNIT										
Line No	Year	Month	AH5	KL2	KL3	KL4	KL5	LIEB1	LIEB2	LIEB3	LIEB4	LS1	MAT1
36		Mar	4 734	900	760	-	12,398	-	567	2 593	-	-	-
37		Apr	1 226	910	835	-	11,619	-	-	1,421	-	-	3,637
38		May	4 777	590	-	-	11,647	-	651	1,388	2 292	0	4,026
39		Jun	6 461		787	-	9 421	-	14	4,245	3 099	-	2 189
40		Jul	12 710	-		-	4,198		1,586	15,234	7,194	-	11 698
41		Aug	7 443	-	-	-	8,438	-	1,262	5,672	8 687	254	541
42		Sep	9 567	-	-	-	30 580	-	1,547	7,157	5 363	3,839	3 507
43		Oct	3,205	-	-	-	4,988	-	595	2,432	2,737	7,351	3,605
44		Nov	6 784	-	-	-	-	-	522	-	1 607	292	1 135
45		Dec	-	-	-	-	-	-	-	-	0	-	-
46	Total 2019		61,215	2,400	2,381	-	103,071	-	6,744	40,139	30,978	11,736	32,561
47	2020	Jan	-	-	-	-	-	-	-	982	313	-	-
48		Feb	-	-	-	-	3 036	-	-	-	-	-	-
49		Mar	781	-	-	-	5 820	-	-	-	-	-	-
50		Apr	-	-	-	-	-	-	-	-	-	-	-
51		May	1 979	-	-	-	4 354	-	-	4 652	2 854	-	1,826
52		Jun	3 498	-	-	-	14 003	-	-	-	2 125	-	2,659
53		Jul	8 341	-	-	-	28 607	-	-	2 182	65	-	704
54		Aug	4 214	-	-	-	23,801	-	-	2,107	4 071	-	2 611
55		Sep	-		-	-	8 263	-	-	-	-	-	-
56		Oct	4 830	-	-	-	31 039	-	-	2 036	4 290	-	4,605
57		Nov	-	-	-	-	1,649	-	-	-	-	-	3 146
58		Dec	-	-	-	-	11,826	-	-	-	-	-	-
50	Total 2020		23,643	-	-	-	132,398	-	-	11,959	13,718	-	15,551
												-	
51	Grand Total		155,802	10,170	7,039	15,663	530,784	-	13,619	109,345	122,289	24,809	75,888

Sponsored by Naim Hakimi

			(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
			MWh PRODUCTION BY UNIT									
Line No	Year	Month	MAT2	MAT3	MAT4	StallA	StallB	StallS	WKL1	WKL2	WKL3	PRK1
36		Mar	974	1 067	532	79 263	84 141	98,317	24 797	-	15,183	330 222
37		Apr	3 691	10 779	13 862	76 890	75 902	93 083	24 415	-	9 997	362,837
38		May	4 071	9 965	6 833	66 878	61 269	78 926	35 121	21 703	13 430	323 675
39		Jun	2 221	3 007	3 093	95 868	96,120	119 630	30,172	20,588	20,517	292,083
40		Jul	11,795	6 497	5 136	105 411	105 645	130,393	24 758	17 508	36 758	295 962
41		Aug	794	4 771	4 637	106,175	106,569	131,973	29,089	40 339	42,109	341 162
42		Sep	6 018	2 363	5 209	101,265	100 912	125,971	8,328	19,331	20,635	-
43		Oct	3 647	2 190	1 755	14 074	14,097	17 221	3 409	7 914	11 423	-
44		Nov	1 165	2,185	2 236	0	0	0	23 752	17,668	13 418	83 132
45		Dec	-	-	84	11 330	6,039	7 924	29 971	3 221	-	150,887
46	Total 2019		38,192	42,825	43,375	788,301	783,405	957,842	282,709	157,383	190,814	2,990,914
47	2020	Jan	-	-	1 684	94 741	98,869	104,737	27 032	6,544	-	212,753
48		Feb	-	-	-	108 779	109 465	126 214	13 625	10 801	-	208 016
49		Mar	-	-	-	90 838	90 874	109 494	28 877	-	2 835	195 389
50		Apr	-	-	-	101,856	101,029	123,790	28 346	2 144	8 912	130,212
51		May	1 854	1 100	1 093	35 373	35 629	42 088	20 798	8 895	1 573	26 290
52		Jun	2 087	1,963	2 679	88,860	88 911	108,056	23,219	55,407	45,028	50,993
53		Jul	1 756	1 672	2 329	110 837	110,953	134 263	32 245	62 105	73 415	218 503
54		Aug	699	1 190	3 097	106 261	106,211	130 356	31 475	27 676	61,824	230,843
55		Sep	-	484	-	101 839	101 817	124,601	6 481	7 487	24,243	13,681
56		Oct	5 160	2,510	4 666	33,246	33 237	39 208	18 255	13 593	-	52 206
57		Nov	2,975	-	-	103,887	103 251	123 200	31,418	4,286	-	236 418
58		Dec	-	-	-	109,721	109,333	128,905	19,488	2,896	-	285,518
50	Total 2020		14,531	8,919	15,548	1,086,238	1,089,579	1,294,917	281,259	201,834	217,830	1,860,822
51	Grand Total		86,221	79,588	99,929	4,080,932	4,036,702	4,976,166	1,208,503	751,680	668,319	15,885,579

Sponsored by Naım Hakımı

SOUTHWESTERN ELECTRIC POWER COMPANY
MWh PRODUCTION BY UNIT
JANUARY 2012 THROUGH JUNE 2016

			(22)	(23)	(24)	(25)	(26)	(27)	(28)
			MWh PRODUCTION BY UNIT						
Line No	Year	Month	DH1	WSH1	WSH2	WSH3	FC	TK	Sub Total
36		Mar	11 995	191 219	-	254 238	121 860	244 517	1,480,276
37		Apr	-	69 764	-	164 886	-	179 899	1,105,654
38		May	38 781	247 990	-	182 656	99 828	81 373	1,297,870
39		Jun	107 916	200,925	-	189 694	112 019	199,503	1,519,572
40		Jul	114,897	225 061	-	198 470	124 455	206,275	1,661,641
41		Aug	114 425	214 065	-	205 990	117 885	203 062	1,695,340
42		Sep	134,158	233 668	-	152 631	122,260	209 663	1,303,972
43		Oct	8 574	200 443	-	33 167	76,580	202,248	621,655
44		Nov	-	208 038	-	214 567	46 605	220 700	843,806
45		Dec		52,824	-	193 707	53 057	211,789	720,832
46	Total 2019		530,746	2,276,149	-	2,268,470	1,172,897	2,411,895	15,227,141
47	2020	Jan	-	-	-	151 550	78 609	177,382	955,196
48		Feb	-	-	-	150 948	79 840	162,524	973,248
49		Mar	-	-	-	167,683	6 047	171 915	870,553
50		Apr	-	84 643	-	50,792	-	130,998	762,722
51		May	509	178 769	-	104 818	27,036	54,447	555,937
52		Jun	86 449	181,345	-	96 082	88,949	154 678	1,096,991
53		Jul	17 629	216 542	-	162 140	111 969	216 851	1,513,113
54		Aug	46 474	252 594	-	191 510	134 555	231,246	1,592,815
55		Sep	79 522	123 982	-	76 559	111 705	186,240	966,904
56		Oct	50 383	43 446	-	211 413	123,528	157,331	834,982
57		Nov	4	219 160	-	192 747	79,282	238,072	1,339,495
58		Dec	-	268,348	-	196,868	106,324	252,205	1,491,432
50	Total 2020		280,970	1,568,829	-	1,753,110	947,844	2,133,889	12,953,388
51	Grand Total		3,064,487	11,241,762	-	10,449,544	5,577,782	11,051,242	74,323,844

Sponsored by: Naim Hakimi

			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			LIGNITE-FIRED PRODUCTION			COAL-FIRED PRODUCTION					
Line No	Year	Month	PRK1	DH1	Sub Total	WSH1	WSH2	WSH3	FC	TK	Sub Total
1	2016	Jul	444 452	204 687	649,139	258,140	-	224,041	140,591	219,438	842,210
2		Aug	412,805	187 338	600,143	249,334	-	263,565	162,613	238,950	914,462
3		Sep	453 672	127,142	580,814	257 380	-	225,677	169,610	239,615	892,283
4		Oct	425 708	89,892	515,600	311,213	-	92,226	69,443	251 785	724,666
5		Nov	146 735	48,457	195,192	70,579	-	245,706	74,546	178,351	569,182
6		Dec	474 632	112 966	587,598	247 539	-	333,461	164,482	163 409	908,891
7	July - December 2016		2,358,005	770,482	3,128,487	1,394,184	-	1,384,676	781,285	1,291,548	4,851,693
8	2017	Jan	463 523	148 622	612,144	303,955	-	294,948	142,975	243,095	984,973
9		Feb	393,531	108,207	501,738	196 341	-	240,447	130,961	214,310	782,059
10		Mar	349,616	27,456	377,072	282 496	-	18 050	158,392	240,459	699,397
11		Apr	-	70,624	70,624	315 722	-	75 978	107,815	236,754	736,268
12		May	190 578	186,119	376,697	279,951	-	194 172	-	128,972	603,095
13		Jun	301,252	183 230	484,481	275,975	-	249 782	49 199	232,314	807,270
14		Jul	392,902	128 062	520,964	322,967	-	318,814	151,653	252,969	1,046,403
15		Aug	464 182	54 788	518,970	282,374	-	298,575	159,424	239,835	980,208
16		Sep	417,508	-	417,508	299,912	-	69,171	116,322	234 193	719,598
17		Oct	328,008	-	328,008	64 558	-	73 172	119,086	225,115	481,931
18		Nov	439,204	-	439,204	238,822	-	290,686	126,488	222,208	878,204
19		Dec	445,336	-	445,336	296,864	-	288,345	125 883	232,780	943,871
20	Total 2017		4,185,640	907,108	5,092,748	3,159,936	-	2,412,139	1,388,198	2,703,004	9,663,278
21	2018	Jan	453,403	83,163	536,566	268,955	-	261 217	150,687	228,257	909,116
22		Feb	382 323	64 457	446,780	206 293	-	97 059	119,664	205 782	628,799
23		Mar	438 268	-	438,268	200,416	-	125,282	4,478	224 327	554,504
24		Apr	116 663	-	116,663	169 148	-	232,927	-	209,192	611,267
25		May	453 299	18 568	471,867	44,924	-	251,070	63 035	37 103	396,132
26		Jun	437 049	83 337	520,386	225,496	-	255,539	130,528	216,868	828,431
27		Jul	381 919	80 748	462,667	273,490	-	269 760	133,517	237 973	914,740
28		Aug	464,547	85,624	550,171	263,354	-	259,032	138,710	240 990	902,087
29		Sep	445,092	86,351	531,443	227,603	-	227 290	119 776	197 802	772,472
30		Oct	333,414	55,167	388,581	308,877	-	119,768	92 752	197,105	718,501
31		Nov	294,219	-	294,219	311 249	-	218,926	162,357	254,882	947,414
32		Dec	270 561	-	270,561	318,067	-	313,278	164 206	246,264	1,041,815

Sponsored by Naım Hakımı

SOUTHWESTERN ELECTRIC POWER COMPANY
MWh PRODUCTION BY UNIT - COAL, LIGNITE
JANUARY 2012 THROUGH JUNE 2016

			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			LIGNITE-FIRED PRODUCTION			COAL-FIRED PRODUCTION					
Line No	Year	Month	PRK1	DH1	Sub Total	WSH1	WSH2	WSH3	FC	TK	Sub Total
33	Total 2018		4,470,757	557,415	5,028,173	2,817,873	-	2,631,149	1,279,710	2,496,546	9,225,277
34	2019	Jan	468,185	-	468,185	268,135	-	260,490	159,279	235,319	923,223
35		Feb	341 752	-	341,752	162,779	-	217,973	139 005	216 878	736,635
36		Mar	329,253	11 995	341,248	190 896	-	254,238	121,684	244,380	811,197
37		Apr	362 273	-	362,273	68 159	-	164,886	-	179,834	412,880
38		May	322 892	38 781	361,673	247,320	-	182,656	99,297	80,090	609,364
39		Jun	291,242	106,710	397,952	200 021	-	189,694	111,909	199,343	700,967
40		Jul	294 990	114,411	409,401	224,419	-	198 470	124,349	206 183	753,421
41		Aug	340 664	113,568	454,232	213 343	-	205,990	117 772	202,965	740,070
42		Sep	-	133,483	133,483	233,343	-	152,631	122,164	209,562	717,699
43		Oct	-	8 210	8,210	199,209	-	33 167	76,496	202 136	511,008
44		Nov	79 918		79,918	207,457	-	214,567	45,875	220,882	688,781
45		Dec	150 009	-	150,009	52,318	-	193,707	52,493	211 726	510,244
46	Total 2019		2,981,179	527,158	3,508,337	2,267,399	-	2,268,470	1,170,323	2,409,298	8,115,491
47	2020	Jan	212 753	-	212,753	-	-	151 481	78,544	177,326	407,351
48		Feb	207 174	-	207,174	-	-	150,773	79,755	162,482	393,010
49		Mar	191 706	-	191,706	-	-	167,493	6,019	171,797	345,309
50		Apr	134 861	-	134,861	84,643	-	50,792	-	130,998	266,433
51		May	26 081	509	26,590	178,769	-	104,818	26,266	54 447	364,300
52		Jun	49 101	85 903	135,004	181 345	-	96,082	88,550	154 678	520,655
53		Jul	217,773	15,413	233,186	216,542	-	162,140	111,657	216,851	707,190
54		Aug	230 486	45 232	275,718	252,594	-	191,510	134 446	231,246	809,796
55		Sep	13 636	78,592	92,228	123,982	-	76,559	111,585	186,240	498,366
56		Oct	50 735	46 292	97,027	43,446	-	211 413	123,211	157,331	535,401
57		Nov	235 031	-	235,031	219,160	-	192 747	78,938	238,072	728,917
58		Dec	284,539	-	284,539	268,348	-	196,868	105,811	252,205	823,232
50	Total 2020		1,853,876	271,941	2,125,817	-	-	469,747	944,782	511,605	6,399,960
51	Grand Total		15,849,456	3,034,105	18,883,561	9,639,393	-	9,166,181	5,564,299	9,412,001	38,255,700

Sponsored by Naim Hakimi

SOUTHWESTERN ELECTRIC POWER COMPANY
MWh PRODUCTION BY UNIT - NATURAL GAS\OIL
JANUARY 2012 THROUGH JUNE 2016

			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
			GAS (OIL)-FIRED PRODUCTION														
Line No	Year	Month	AH5	KL2	KL3	KL4	KL5	LIEB1	LIEB2	LIEB3	LIEB4	LS1	MAT1	MAT2	MAT3	MAT4	StallA
1		Jul	7 932	1 243	1 467	4 180	21 839	-		2 412	8 165	2 210	3 728	2 890	777	34	105 741
2		Aug	4 447	579	346	2 075	24 517	-	328	2 759	4 101	1,117	3 662	3 929	660	604	104 468
3		Sep	3 285	317		1 163	27 551	-	352	-	1 872	568	2 062	2 140	3 244	3 218	94 442
4		Oct	4 194	311	-	2 269	32 676	-	914	5,024	8,582	1 644		1 122		1 106	68
5		Nov	-	406	406	974	1 294	-	312	-	4 820	484		684		688	85 456
6		Dec	955	264	-		4 782	-	330		-		-				84 428
7	July - December 2016		20,812	3,120	2,219	10,661	112,659	-	2,235	10,194	27,541	6,024	9,452	10,766	4,681	5,650	474,603
8	2017	Jan	-		-	69	3 218			-		-		-		-	79 608
9		Feb					-		-	-	-	-		-			59,475
10		Mar	-					-		-	-	-	-	-	-	-	84,764
11		Apr	3 806		-	2 088	-			-	1 257	-	-	-	-	-	65 464
12		May	-		-	-		-	-	-	-	-	-	1 870		-	88,229
13		Jun	3 548	-		-	5 854	-	-	2 576	-	-	-	1 853	2 707	5 388	91 251
14		Jul	2 956	511	469	989	24 881	-	388	3 982	3,292	-	2,646	653	4 055	4 364	97,624
15		Aug	-	-	-	-	-	-	-	-		1 131	1 801	1 781	2,087	2 255	95 539
16		Sep	868			815	5 768	-	-	994	1 019	-	81	-	1 021	3 755	77 745
17		Oct	964	300	336	1 040	5 553	-	-	1 214	2 178	-	1 818	1 845	1 827	1,844	83 268
18		Nov	12 463		-	-	-	-	-	7 891	10,221	-	-	-	1 081	4 757	
19		Dec						-		-		-	49		58	1 029	61 763
20	Total 2017		24,607	811	804	5,002	45,274	-	388	16,658	17,967	1,131	6,395	8,002	12,834	23,391	884,731
21	2018	Jan	2 949	569	223		21 864	-	365	1 513	4,279	583	1,394	1 376	-	1,312	95 332
22		Feb	-		-		-			-		-			-	-	80 210
23		Mar	-	-	-		2 794			-			-	-	-	-	88 748
24		Apr	3 221	281	-	-	2 111	-	649	2 873	4,453	1	1 910	1 923	-	-	63,260
25		May	5 506	-	-		41 799	-	1 280	10 914	4,513	1 897	2 330	4,750	2 610	2,525	87 740
26		Jun	2,497	247	-	-	20 256			3 491	1,292	708	-	-	1 820	1 829	95 100
27		Jul	4 752	1 013	953		26 058		1 035	5 402	5 949	2 001	2 786	2 199	2,071	2,512	102 733
28		Aug	2 254	337	-		13 797		356	6 178	4 330	-	1 109	1 376	840	1 338	92,553
29		Sep	2 614				-	-		-	-	-	244	322	-	-	66 693
30		Oct	-	418	-	-		-			552			-	552	-	16 459
31		Nov	1 733	973	459		3 015		567	-	6 718	728	2 156	2 784	2,437	2,450	21 710
32		Dec	-	-	-	-	5 688	-	-	23		-	-	-	-	-	36 523
33	Total 2018		25,526	3,839	1,635	-	137,382	-	4,252	30,394	32,086	5,918	11,929	14,730	10,329	11,965	847,059

Sponsored by Naim Hakimi

SOUTHWESTERN ELECTRIC POWER COMPANY
MWh PRODUCTION BY UNIT - NATURAL GAS\OIL
JANUARY 2012 THROUGH JUNE 2016

			(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)
				GAS (OIL)-FIRED PRODUCTION									
Line No	Year	Month	StallB	StallS	WKL1	WKL2	WKL3	PRK1	DH1	WSH	FC	TK	Sub Total
1		Jul	105,060	131 955	28 728	54 051		631	476	1 553	275	574	485,922
2		Aug	103,976	131 063	32 191	49 836		655	299	1 799	266	160	473,837
3		Sep	94 579	122 050	5 555	37 628		62	479	831	4	141	401,543
4		Oct	24	82	17 929	-	-	91	213	396	205	98	76,946
5		Nov	83 620	100 255	32 391			1,920	44		726	701	315,180
6		Dec	83 358	100 816	30 169	-		28	1,449	1 666	19	1 787	310,049
7	July - December 2016		470,617	586,221	146,962	141,514	-	3,387	2,960	6,245	1,495	3,461	2,063,478
8	2017	Jan	58 481	84 616	28 335		-	430	976	1 049	421	574	257,778
9		Feb	58 195	74 449	26,285	-	-	539	95	1 125	41	60	220,264
10		Mar	85,069	108,112	31,328		-	83	146	569	25	447	310,544
11		Apr	65 469	83 154	27 347	-	-	-	52	1 143	58	45	249,884
12		May	88 845	115,012	30 996		7 414	3 386	799	1,528	-	1 483	339,563
13		Jun	91 535	118,507	26 309	13 701	2,456	954	521	798	902	671	369,532
14		Jul	97 664	125 225	30 936	16 705	30 887	1 412	572	432	206	69	450,919
15		Aug	95 438	120 901	25 942	3 093	7 820	5	470	854	27	95	359,239
16		Sep	78 684	101 591	12 648	21 177	17,416	240	-	713	584	56	325,175
17		Oct	83 925	107 113	-	28 232	14 061	1 478	-	1 058	399	669	339,121
18		Nov	-	-	648	2 625	-	583	-	765	250	(535)	40,749
19		Dec	79 453	78 777	20 009	4 609	3 651	(4)	-	663	262	69	250,389
20	Total 2017		882,759	1,117,456	260,784	90,143	83,705	9,106	3,631	10,697	3,175	3,703	3,513,156
21	2018	Jan	94 574	109,699	20,255	18 569	-	544	122	465	42	723	376,749
22		Feb	79 834	93 607	28 754	-	-	1 034	5 526	426	539	808	290,738
23		Mar	86 850	104 843	17 168		3 026	132	-	927	354	79	304,921
24		Apr	62 188	75 011	33 568		13 182	1 493	-	575	-	173	266,874
25		May	89 176	111 491	22 682		3 573	335	-	1 827	984	2,402	398,335
26		Jun	92 434	121 019		30 341	41 437	220	1 853	442	274	1 450	416,709
27		Jul	85 856	119 280	24 011	43,723	59 282	1,128	227	354	298	(589)	493,035
28		Aug	88 788	116 684	26 226	18 178	12 319	32	1 144	703	44	43	388,629
29		Sep	63 784	84 854	15 754	7 038	9 667	48	1 157	525	109	(69)	252,741
30		Oct	15 936	20 749	11 728	13 793	10 835	585	1 145	353	484	2 095	95,685
31		Nov	13 997	19 767	17 519	15 445	20 529	577	-	999	18	16	134,595
32		Dec	36 924	42,725	19 122	13 720	2 119	821	-	252	31	65	158,013
33	Total 2018		810,342	1,019,730	236,789	160,807	175,969	6,949	11,174	7,848	3,177	7,196	3,577,025

Sponsored by Naim Hakimi

			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
			GAS (OIL)-FIRED PRODUCTION														
Line No	Year	Month	AH5	KL2	KL3	KL4	KL5	LIEB1	LIEB2	LIEB3	LIEB4	LS1	MAT1	MAT2	MAT3	MAT4	StallA
34	2019	Jan	4 308				2 240						1 671	2 680			58 273
35		Feb					7 542						552	1 136			72 874
36		Mar	4,734	900	760		12 398		567	2 593			-	974	1 067	532	79 263
37		Apr	1,226	910	835		11 619			1 421		-	3 637	3 691	10 779	13 862	76 890
38		May	4 777	590			11 647		651	1 388	2 292	0	4 026	4 071	9 965	6 833	66 878
39		Jun	6 461		787		9 421		14	4 245	3 099		2 189	2 221	3 007	3 093	95 868
40		Jul	12 710				4 198		1 586	15 234	7 194		11,698	11 795	6 497	5 136	105 411
41		Aug	7 443				8 438		1 262	5 672	8 687	254	541	794	4 771	4 637	106 175
42		Sep	9,567				30 580		1 547	7 157	5 363	3 839	3 507	6 018	2 363	5 209	101 265
43		Oct	3 205				4 988		595	2 432	2 737	7 351	3 605	3 647	2 190	1 755	14 074
44		Nov	6 784						522	-	1 607	292	1 135	1 165	2 185	2,236	
45		Dec				-					0		-			84	11 330
46	Total 2019		61,215	2,400	2,381	-	103,071	-	6,744	40,139	30,978	11,736	32,561	38,192	42,825	43,375	788,301
47	2020	Jan								982	313					1 684	94,741
48		Feb					3,036		-			-		-			108 779
49		Mar	781				5 820							-			90 838
50		Apr				-				-							101 856
51		May	1 979	-		-	4 354			4 652	2 854		1,826	1 854	1 100	1 093	35 373
52		Jun	3 498			-	14 003		-		2 125		2 659	2 087	1 963	2 679	88,860
53		Jul	8 341				28 607			2 182	65	-	704	1 756	1 672	2 329	110 837
54		Aug	4,214				23 801			2 107	4,071		2,611	699	1 190	3 097	106 261
55		Sep					8 263		-				-		484		101 839
56		Oct	4 830				31 039			2 036	4 290		4,605	5 160	2 510	4 666	33 240
57		Nov	-				1 649			-	-		3 146	2 975			103 887
58		Dec	-	-	-	-	11,826	-	-	-	-	-	-	-	-	-	109,721
50	Total 2020		23,643	-	-	-	132,398	-	-	11,959	13,718	-	15,551	14,531	8,919	15,548	1,086,238
51	Grand Total		155,802	10,170	7,039	15,663	530,784	-	13,619	109,345	122,289	24,809	75,888	86,221	79,588	99,929	4,080,932

Sponsored by Naim Hakimi

SOUTHWESTERN ELECTRIC POWER COMPANY
MWh PRODUCTION BY UNIT - NATURAL GAS\OIL
JANUARY 2012 THROUGH JUNE 2016

			(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)
				GAS (OIL)-FIRED PRODUCTION									
Line No	Year	Month	StallB	StallS	WKL1	WKL2	WKL3	PRK1	DH1	WSH	FC	TK	Sub Total
34	2019	Jan	60,055	69,615	23 696	5 551	3 731	267	-	268	21	83	232,459
35		Feb	72 656	84 787	25 201	3 559	3 614	749	-	970	43	586	274,270
36		Mar	84 141	98 317	24 797	-	15 183	969	-	323	176	137	327,830
37		Apr	75 902	93 083	24 415	-	9 997	564	-	1 605	-	65	330,501
38		May	61 269	78 926	35 121	21 703	13 430	783	-	670	531	1,283	326,833
39		Jun	96 120	119,630	30 172	20 588	20 517	841	1 206	904	110	160	420,652
40		Jul	105 645	130 393	24 758	17 508	36 758	972	486	642	106	92	498,819
41		Aug	106,569	131,973	29 089	40 339	42 109	498	857	722	113	97	501,038
42		Sep	100,912	125 971	8 328	19 331	20 635	-	675	325	96	101	452,789
43		Oct	14 097	17 221	3 409	7 914	11 423	-	364	1 234	84	112	102,437
44		Nov	-	-	23 752	17 668	13 418	3 214	-	581	730	(182)	75,106
45		Dec	6 039	7 924	29 971	3 221	-	878	-	506	564	63	60,579
46	Total 2019		783,405	957,842	282,709	157,383	190,814	9,735	3,588	8,750	2,574	2,597	3,603,313
47	2020	Jan	98 869	104 737	27 032	6 544				69	65	56	335,092
48		Feb	109 465	126 214	13 625	10 801		842	-	175	85	42	373,064
49		Mar	90 874	109 494	28 877	-	2 835	3 683	-	190	28	118	333,538
50		Apr	101,029	123 790	28,346	2,144	8 912	(4,649)	-	620	-	87	362,135
51		May	35 629	42 088	20 798	8 895	1 573	208		916	769	1 830	167,791
52		Jun	88 911	108 056	23 219	55 407	45 028	1 892	546	1 289	400	759	443,381
53		Jul	110 953	134 268	32,245	62 105	73 415	730	2 215	4 140	312	605	577,481
54		Aug	106 211	130 356	31 475	27 676	61 824	356	1 242	711	109	110	508,121
55		Sep	101 817	124 601	6 481	7 487	24 243	45	930	550	121	955	377,816
56		Oct	33 237	39 208	18 255	13 593	-	1 471	4,091	1,567	317	1 057	205,178
57		Nov	103 251	123 200	31 418	4 286	-	1 387	4	991	343	40	376,577
58		Dec	109,333	128,905	19,488	2,896	-	979	-	702	513	62	384,425
50	Total 2020		1,089,579	1,294,917	281,259	201,834	217,830	6,944	9,028	11,920	3,062	5,721	4,444,599
51	Grand Total		4,036,702	4,976,166	1,208,503	751,680	668,319	36,121	30,381	45,460	13,483	22,678	17,201,571

Sponsored by Naım Hakımı

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO SIERRA CLUB'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. SC 2-10:

Provide the Company's most-recent Fundamentals Forecast, including base band commodity and power market price forecasts. Indicate the date of such AEP Fundamentals Forecast.

Response No. SC 2-10:

The Company's most-recent Fundamentals Forecast is provided as Sierra Club 2-10 Confidential Attachment 1.

The attachment responsive to this request is CONFIDENTIAL MATERIAL under the terms of the Protective Order. Due to current restrictions associated with COVID-19, this information is being provided electronically and a secure login to access the information will be provided upon request to individuals who have signed the Protective Order Certification.

Prepared By: Thomas W. Freeman	Title: Resource Planning Anlyst Staff
Sponsored By: Thomas P. Brice	Title: VP Regulatory & Finance

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO SIERRA CLUB'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. SC 2-11:

Refer to the following Schedule, Attachments, and Exhibits. Confirm whether the values represent whole plant or just SWEPCO share. For Turk, indicate whether the values include the Arkansas share.

a. SWEPCO response to SC 1-7, Attachment 2.
b. SWEPCO response to SC 1-7, Attachment 3.
c. Schedule H-12.2a & 12.2a1
d. Schedule H-5.2b
e. Schedule H-5.3b

Response No. SC 2-11:

a. Total plant.
b. SWEPCO share.
c. SWEPCO share.
d. SWEPCO share.
e. SWEPCO share.

Prepared By: Tara D. Beske	Title: Regulatory Consultant Staff
Prepared By: Scott E. Mertz	Title: Regulatory Consultant Staff
Prepared By: Michael H. Ward	Title: Regulatory Consultant Staff
Sponsored By: Amy E. Jeffries	Title: Coal Procurement Mgr
Sponsored By: Monte A. McMahon	Title: VP Generating Assets SWEPCO
Sponsored By: Scott E. Mertz	Title: Regulatory Consultant Staff

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO SIERRA CLUB'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. SC 2-12:

Indicate the percentage of Turk costs, revenues, and generation allocated to SWEPCO for the non-merchant share of the plant in this docket.

Response No. SC 2-12:

Turk costs, revenues, and generation are not allocated to SWEPCO. SWEPCO owns 73.33% (440 MW) of the Turk plant and allocates the investment, investment related costs, and O&M to the Texas retail jurisdiction using a production demand allocator of 36.9072% as discussed in the direct testimony of SWEPCO witness John Aaron. Turk associated fuel costs, revenues and generation are not pertinent to this proceeding but instead are reflected in SWEPCO fuel related filings.

Prepared By: John O. Aaron Title: Dir Reg Pricing & Analysis

Sponsored By: John O. Aaron Title: Dir Reg Pricing & Analysis

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO SIERRA CLUB'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. SC 2-13:

Provide total energy and ancillary service market revenues by plant for each of SWEPCO's solid fuel units (coal and lignite) for the period 2015 – 2020. Indicate whether the values represent SWEPCO's share or total unit.

Response No. SC 2-13:

Please see Sierra Club 2-13 HIGHLY SENSITIVE Attachment 1 for the requested information. Data prior to May 2015 is not archived and thus is not available.

The attachment responsive to this request is HIGHLY SENSITIVE MATERIAL under the terms of the Protective Order. Due to current restrictions associated with COVID-19, this information is being provided electronically and a secure login to access the information will be provided upon request to individuals who have signed the Protective Order Certification.

Prepared By: Scott E. Mertz	Title: Regulatory Consultant Staff
Sponsored By: Scott E. Mertz	Title: Regulatory Consultant Staff

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO SIERRA CLUB'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. SC 2-14:

Provide total projected energy and ancillary service market revenues by plant for each of SWEPCO's solid fuel unis (coal and lignite) for the period 2021 – 2030. Indicate whether the values represent SWEPCO's share or total unit.

Response No. SC 2-14:

Please see Sierra Club 2-2 for the projected energy market revenues. Ancillary service market revenues are not forecast.

Prepared By: Scott E. Mertz	Title: Regulatory Consultant Staff
Sponsored By: Scott E. Mertz	Title: Regulatory Consultant Staff

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

<u>SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO SIERRA CLUB'S SECOND SET OF REQUESTS FOR INFORMATION</u>

Question No. SC 2-15:

Refer to SWEPCO response to Sierra Club 1-7, Attachment 2. Indicate whether the O&M costs listed under Welsh 0 represent common plant costs. If not, explain what the costs represent.

Response No. SC 2-15:

The Welsh Unit 0 costs included in Sierra Club 1-7 Attachment 2 are common plant costs.

Prepared By: Tara D. Beske — Title: Regulatory Consultant Staff

Sponsored By: Monte A. McMahon — Title: VP Generating Assets SWEPCO

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

<u>SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO SIERRA CLUB'S SECOND SET OF REQUESTS FOR INFORMATION</u>

Question No. SC 2-16:

Please refer to Schedule H-5.3b and Bates stamp pages 5200-02 of the Company's Application.

a. For SWEPCO's solid fuel units, since 2015, has the Company conducted any analyses of compliance control strategies or costs associated with the Regional Haze Rule's best available retrofit technology or "reasonable progress" requirements, including, but not limited to, any four-factor analysis under 40 C.F.R. § 51.308(e)-(f)? If yes, please provide all such analyses, including all supporting calculations, data, documents, technical or economic reports or presentations, modeling input and output files, and workpapers associated with each such analysis. If the Company has not conducted any such analyses, explain why.
b. For SWEPCO's solid fuel units, since 2015, has SWEPCO conducted any analyses of compliance with proposed or finalized EPA regulations for carbon dioxide emissions? If yes, please provide all such analyses, including all supporting calculations, data, documents, technical or economic reports or presentations, modeling input and output files, and workpapers associated with each such analysis. If the Company has not conducted any such analyses, explain why.

Response No. SC 2-16:

a. See Sierra Club 2-16 Attachments 1-5 for documents supporting analyses conducted by the Company with respect to compliance with the Regional Haze Rule.

b. See Sierra Club 2-16 Attachments 6-14 and Highly Sensitive Attachments 15-17 for documents supporting analyses conducted by the Company with respect to compliance with carbon dioxide emissions regulations.

Attachments 15-17 responsive to this request are HIGHLY SENSITIVE MATERIAL under the terms of the Protective Order. Due to current restrictions associated with COVID-19, this information is being provided electronically and a secure login to access the information will be provided upon request to individuals who have signed the Protective Order Certification.

Prepared By: Tara D. Beske	Title: Regulatory Consultant Staff
Sponsored By: Brian Bond	Title: VP External Affairs
Sponsored By: Monte A. McMahon	Title: VP Generating Assets SWEPCO

Welsh FGD/DSI Comparison
Date: 4-25-17

Texas BART Analysis
AEP to EPA Comparison

AEP Reference Number 0014 Revision 01
AACEI Class 5 estimate

Description	DSI				WFGD	
	90% Removal		50% Removal		90% Removal	
	AEP	EPA	AEP	EPA	AEP	EPA
Capital, engineering and construction cost subtotal (CECC $000s)	$ 69,303	$ 19,702	$ 62,006	$ 14,652	$ 579,382	$ 230,424
Civil / Site Infrastructure Development	$ 10,780	$ -	$ 11,564	$ -	$ 28,236	$
BOP	$ 10,607	$ -	$ 11,378	$ -	$ 31,580	$ -
Stack	$	$	$ -	$	$ 51,866	$
FGD Equipment	$	$ -	$ -	$ -	$ 430,303	$
DSI Equipment	$ 47,916	$	$ 39,064	$ -	$	$
ID Fans	$ -	$ -	$ -	$ -	$ 37,398	$
Owners costs including "home office" costs (owner engineering management, and procurement activities) (B1) ($000s)	$ 11,879	$ 985	$ 11,340	$ 733	$ 42,816	$ 11,521
Total project cost without AFUDC (TPC $000s)	$ 81,182	$ 20,687	$ 73,346	$ 15,385	$ 622,198	$ 241,945
AFUDC (zero for less than 1 year engineering and construction cycles) (B2)($000s)	$ 5,320	$	$ 4,806	$	$ 54,959	$ 24,195
Total Project Cost (TPC $000s)	**$ 86,502**	**$ 20,687**	**$ 78,152**	**$ 15,385**	**$ 677,158**	**$ 266,140**
Fixed O&M Cost ($/kW)	$ -	$ 0.77	$ -	$ 0.69	$ 7.76	$ 8.51
Variable O&M Cost ($/MWh)	**$ 1.91**	**$ 7.05**	**$ 0.48**	**$ 3.39**	**$ 1.63**	**$ 1.12**
Annualization						
Capital, engineering and construction cost ($000s)	$ 69,303	$ 19,702	$ 62,006	$ 14,652	$ 579,382	$ 230,424
Capital Recovery factor	8.06%	8.06%	8.06%	8.06%	8.06%	8.06%
Annualized capital costs ($000s)	$ 5,585	$ 1,588	$ 4,997	$ 1,181	$ 46,690	$ 18,569
Variable operating costs ($000s)	$ 6,073	$ 22,376	$ 1,518	$ 10,744	$ 5,186	$ 3,546
Fixed operating costs ($000s)	$	$ 279	$ -	$ 251	$ 2,811	$ 3,081
Total annualized costs ($000s)	**$ 11,658**	**$ 24,243**	**$ 6,515**	**$ 12,175**	**$ 54,687**	**$ 25,196**
SO2 emissions reduction (tons)	5832	5832	3343	3343	6116	6116
$/ton	**$ 1,999**	**$ 4,157**	**$ 1,949**	**$ 3,642**	**$ 8,942**	**$ 4,120**

AEP NOTES

$'s In thousands, except O&M costs
Landfill Operating and Capital cost have been included in variable O&M
Sorbent injection rate of 1.0 TPH was used for DSI 50% SO2 removal calculations (Included in variable O&M costs)
Sorbent injection rate of 4.0 TPH was used for DSI 90% SO2 removal calculations (Included in variable O&M costs)
AEP DSI costs are based on milled SBC, EPA costs are based on milled trona
Reagent (FGD) costs have been included in variable O&M
AEP costs are in 2017 dollars and EPA costs are in 2012 dollars
All AEP calculations are based on first unit installation costs
For annualization cost AEP assumed the same levelization methodology as the EPA
AEP assumed the same annual gross load as the EPA and the same SO2 tonnage removal for ease of comparison

American Electric Power

SOUTHWESTERN ELECTRIC POWER COMPANY
AEP

VIA U.S. Mail and E-mail (*Montgomery@adeq.state.ar.us*)

March 25, 2020

Mr. William K. Montgomery
Interim Associate Director
Arkansas Department of Energy and Environment
Division of Environmental Quality, Office of Air Quality
5301 Northshore Drive
North Little Rock, AR 72118

Re: Response to January 8, 2020 Regional Haze Four-Factor Analysis Information Collection Request Southwestern Electric Power Company - Flint Creek Power Plant

Dear Mr. Montgomery:

This letter is provided by American Electric Power Service Company (AEP) on behalf of Southwestern Electric Power Company (SWEPCO) in response to your January 8, 2020 information collection request ("the ICR") addressed to Mr. Brian Bond. The ICR specifically asks for technical and economic information related to two potential post-combustion nitrogen oxide (NO_X) reduction strategies for the Main Boiler, source number 01 (SN-01), at the Flint Creek Power Plant (Flint Creek): Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR).

As stated in the ICR, SN-01 is already equipped with low-NO_X burners and over-fire air (LNB+OFA), which constitute the most cost-effective combustion controls for NO_X. Thus, the employment of SCR and/or SNCR would be for only incrementally more NO_X emissions reduction than is already being achieved. The requested information for each of these two control options is provided below in a slightly different order/format than outlined in the ICR.

In addition to the information requested by the ICR, AEP/SWEPCO is providing, in Attachment 1, a summary of the current visibility conditions at each of the two Arkansas and two Missouri Class I areas. AEP/SWEPCO feels that it is important to bear in mind the ultimate goal of the regional haze rule and the fact that visibility conditions in all four potentially impacted Class I areas are better than what is required by the uniform rate of progress or glidepath for each area. This is true for both current monitored visibility and modeled projections for visibility. Therefore, the obligation to make reasonable progress toward the 2064 visibility goal is satisfied and further reductions are not necessary during this planning period.

Baseline Emission Rate

Per the ICR, the maximum monthly emission rate, in pounds per hour (lb/hr) or pounds per million British thermal units (lb/MMBtu), from the period between June 1, 2018 and December 31, 2019 (baseline period) is taken as the baseline emission rate. Based on monthly data in the U.S. Environmental Protection

Agency's (EPA's) Air Markets Program Data (AMPD), [1] this value is 0.20 lb/MMBtu for November 2018. November 2018 also represents the maximum monthly heat input for SN-01 for the baseline period: 4,678.4 MMBtu per hour (MMBtu/hr).

The average monthly emission rate and heat input rate during the baseline period are much less: 0.186 lb/MMBtu and 3,856.8 MMBtu/hr, respectively.

Additionally, for the purpose calculating the control cost estimates presented later in this letter, the maximum monthly total emissions value during the baseline period is 345.06 tons per month for December 2018. This value annualizes to 4,140.72 tons per year (tpy).

Control Effectiveness

The ICR lists "typical control efficiency" values for SCR and SNCR of 90% and 35-50%, respectively. These control efficiencies are possible only for boilers that do not already have low emission rates, unlike SN-01, which, as mentioned above, is already equipped with LNB+OFA.

AEP's September 2013 Best Available Retrofit Technology (BART) Five Factor Analysis (the AEP 2013 BART report) presented a vendor-estimated emission rate for SCR of 0.067 lb/MMBtu and an emissions estimate range for SNCR (with LNB+OFA) of 0.18 to 0.23 lb/MMBtu. EPA's August 2016 Federal Implementation Plan (FIP) Response to Comments (RTC) document (the EPA 2016 FIP RTC)[2] used 0.055 lb/MMBtu rather than 0.067 lb/MMBtu for SCR, and it used 0.20 lb/MMBtu for SNCR.

For the purposes of this ICR response, 0.055 lb/MMBtu is used as the controlled emission rate for SCR. Comparing this controlled emission rate to the baseline emission rate of 0.20 lb/MMBtu, the control efficiency possible for SCR is 72.5%. AEP/SWEPCO agrees that 0.20 lb/MMBtu is the appropriate emission rate for SNCR at Flint Creek. This rate is equal to the baseline emission rate; therefore, the SNCR control efficiency is zero (0). AEP's engineering department is in agreement with this result – since the NOx emission rate is already reduced to this lower emission rate range by the installed LNB/OFA, implementing SNCR at Flint Creek would provide for no additional emissions reductions.

Emissions Reductions

Based on the control efficiencies presented above and the baseline period annualized maximum monthly total emissions value, 4,140.72 tpy, the potential emissions reductions for SCR and SNCR are 3,002 tpy and zero (0) tpy, respectively.

Time Necessary to Implement

Were SCR or SNCR to be required for SN-01, AEP/SWEPCO would need at least three (3) years for engineering design, procurement, construction, and shakedown.

[1] https://ampd.epa.gov/ampd/, queried on March 2, 2020.

[2] Response to Comments for the Federal Register Notice for the State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan, Docket No. EPA-R06-OAR-2015-0189, August 31, 2016. See page 211.

Remaining Useful Life

There are no effective limitations on the remaining useful life (RUL) of SN-01; therefore, the default useful life values for SCR and SNCR from the EPA's Air Pollution Control Cost Manual (CCM),[3] 30 years and 20 years, respectively, are used for the control cost estimates presented later in this letter.

Energy and Non-Air Quality Environmental Impacts

From the AEP 2013 BART report:

> *SCR systems require electricity to operate the ancillary equipment. The need for electricity to help power some of the ancillary equipment creates a demand for energy that currently does not exist.*
>
> *SCR and SNCR can potentially cause significant environmental impacts related to the storage of ammonia. The storage of aqueous ammonia above 10,000 lbs is regulated by a risk management program (RMP), since the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release. SCR and SNCR will likely also cause the release of unreacted ammonia to the atmosphere. This is referred to as ammonia slip. Ammonia slip from SCR and SNCR systems occurs either from ammonia injection at temperatures too low for effective reaction with NO_X, leading to an excess of unreacted ammonia, or from over-injection of reagent leading to uneven distribution, which also leads to an excess of unreacted ammonia. Ammonia released from SCR and SNCR systems will react with sulfates and nitrates in the atmosphere to form ammonium sulfate and ammonium nitrate. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze.*

Costs to Implement

Table 1 summarizes the capital, annualized capital, and annual operations and maintenance (O&M) costs for SCR and SNCR as presented in the AEP 2013 BART report and alternative values for SNCR as presented in the EPA 2016 FIP RTC. As discussed in the EPA 2016 FIP RTC, the EPA's alternative values for SNCR include adjustments to the useful life and baseline/uncontrolled emission rate.

Table 1. Controls Costs

Control Option	Capital Cost ($)	Annualized Capital Cost ($/yr)	Annual O&M Cost ($/yr)	Total Annual Cost ($/yr)
SCR	121,440,000	9,786,413	5,260,000	15,046,413 (2016 Basis) 13,769,599 (2013 Basis)
SNCR - AEP [4]	7,124,235	672,477	2,050,684	2,723,162 (2011 Basis)
SNCR - EPA	5,683,091	457,980	325,551	783,531 (2011 Basis)

Table 2 presents cost effectiveness, in dollars per ton of NO_X reduced, based on the total annual costs in Table 1 and the emissions reductions values presented above. As noted in Table 1 above, the SCR costs were calculated in the AEP 2013 BART report using a 2016 basis, and the total was then de-escalated to a

[3] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost reports, accessed on March 2, 2020.

[4] The SNCR values are adjusted to remove the costs associated with LNB+OFA; they were presented together in the AEP 2013 BART report.

2013 basis. Additionally, the SNCR costs were calculated and presented using a 2011 basis. These values are escalated to a 2018 basis[5] for the purpose of calculating updated cost effectiveness values.

Table 2 – Controls Cost Effectiveness

Control Option	Total Annual Cost ($/yr) (2018 Basis)	Emissions Reduction (tpy)	Cost Effectiveness ($/ton)
SCR	15,962,740	3,002	5,317
SNCR - AEP	3,349,146	0	Not applicable
SNCR - EPA	963,644	0	Not applicable

Conclusion

Based on the updated emissions and controls cost information presented by AEP (and accepted by the EPA) and information published independently by the EPA in the BART determinations, post-combustion NO_X controls (i.e., SCR and SNCR) remain infeasible for SN-01.

This response is submitted on behalf of Southwestern Electric Power Company, a wholly owned subsidiary of American Electric Power, Inc. (AEP). Please contact me at (214) 777-1155 or kmhughes@aep.com if you have any questions regarding this submittal. Due to the COVID-19 pandemic situation and limited access to print, scan and postal mail abilities, please accept my electronic signature below.

Sincerely,

Kimberly Hughes

Kimberly Hughes
Environmental Engineering Supervisor
American Electric Power

ec: Jeremy Jewell, Trinity Consultants

Brian Bond/Elizabeth Gunter/Ashley Roundtree, AEP

File: FLC.10.90.50.10.2020

[5] Escalation is based on 3 % per year increased costs

Attachment 1

Visibility Conditions in the Arkansas and Missouri Class I Areas

The following pages show plots for each of the Arkansas and Missouri Class I Areas – Caney Creek (CACR), Hercules Glades (HEGL), Mingo (MING), and Upper Buffalo (UPBU) – from EPA's September 19, 2019 memorandum *Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling.* In each plot, the "Current Avg" line represents the current visibility conditions based on the average of the 20 percent most impaired days for the years 2014 through 2017 from the Interagency Monitoring of Protected Visual Environments (IMPROVE) data, the hatched bars ("MOD2016" and "MOD2028") show the results of EPA's modeling, and the "Adj Glidepath" line shows EPA's expected new uniform rate of progress (URP) based on the 20 most impaired days (rather than the 20 percent worst days, which was used for the original URP/Glidepath). The shaded area shows EPA's expectations for the minimum and maximum adjusted glidepath – to be established with the approval of the regional haze second planning period state implementation plan (SIP). Thus, as plotted, if the "Current Avg" is below the "Adj Glidepath" and especially if it is even the lower than the shaded area, then the current Class I area visibility conditions are better than necessary to achieve the goal of the regional haze program. Moreover, if the 2028 modeling results are lower than the "Adj Glidepath" and shaded areas, then predicted visibility conditions are better than necessary. Both of these are true of all four Class I areas under consideration in the Arkansas SIP.

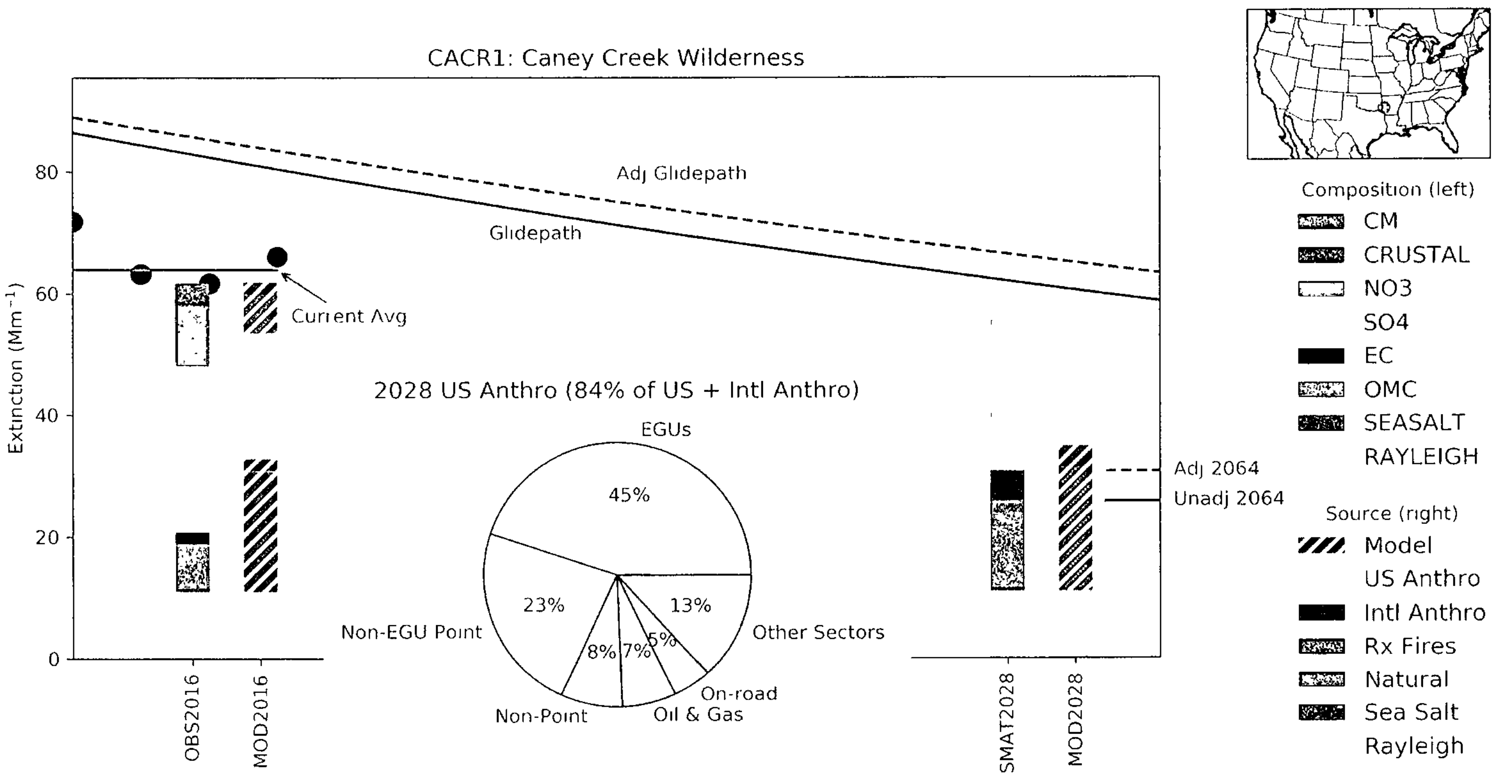

Figure 16: 2014-2017 IMPROVE observations, 2016 CAMx model predictions, 2028 modeled projection, and 2028 sector contributions at CACR1. Used for Class I areas: Caney Creek Wilderness.

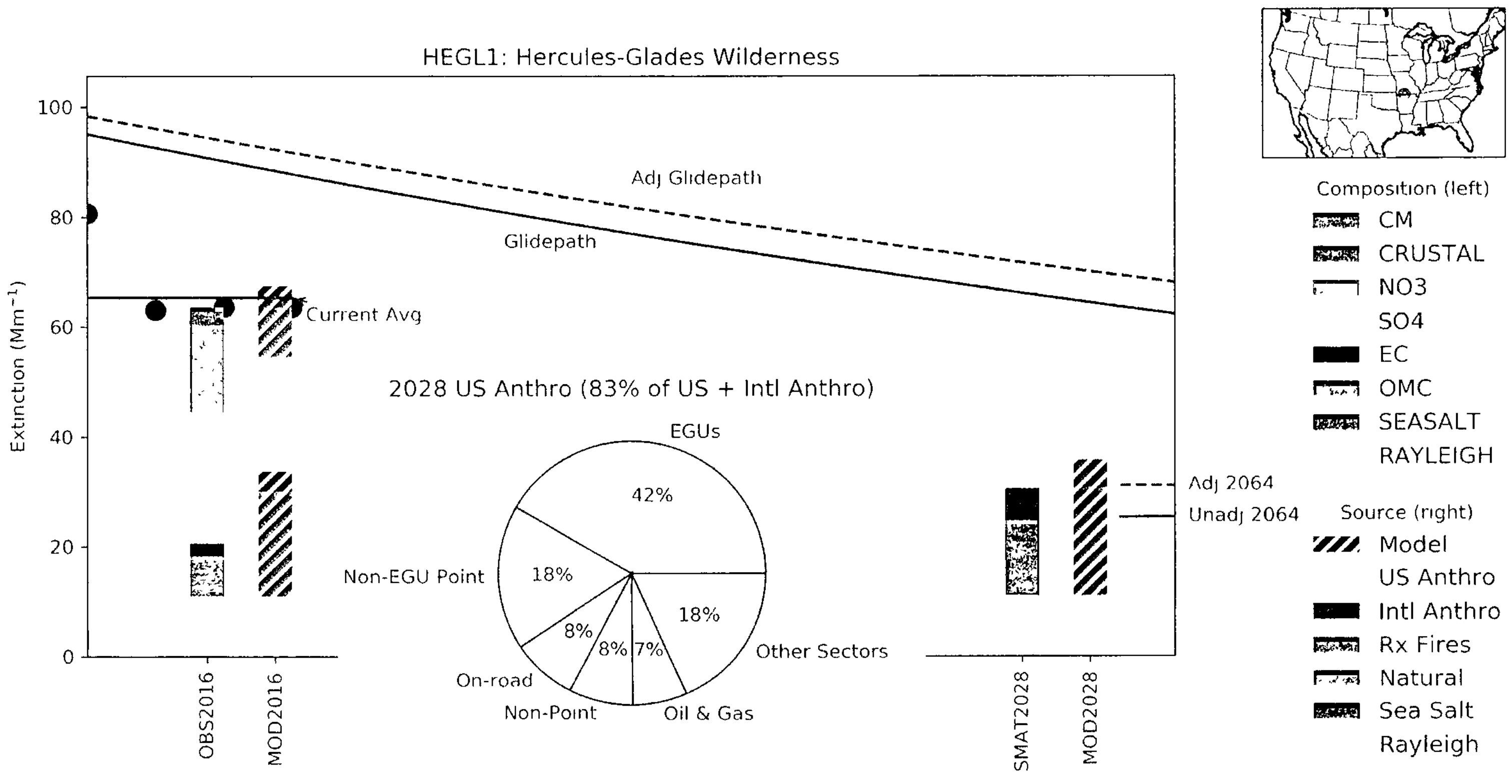

Figure 36: 2014-2017 IMPROVE observations, 2016 CAMx model predictions, 2028 modeled projection, and 2028 sector contributions at HEGL1. Used for Class I areas: Hercules-Glades Wilderness.

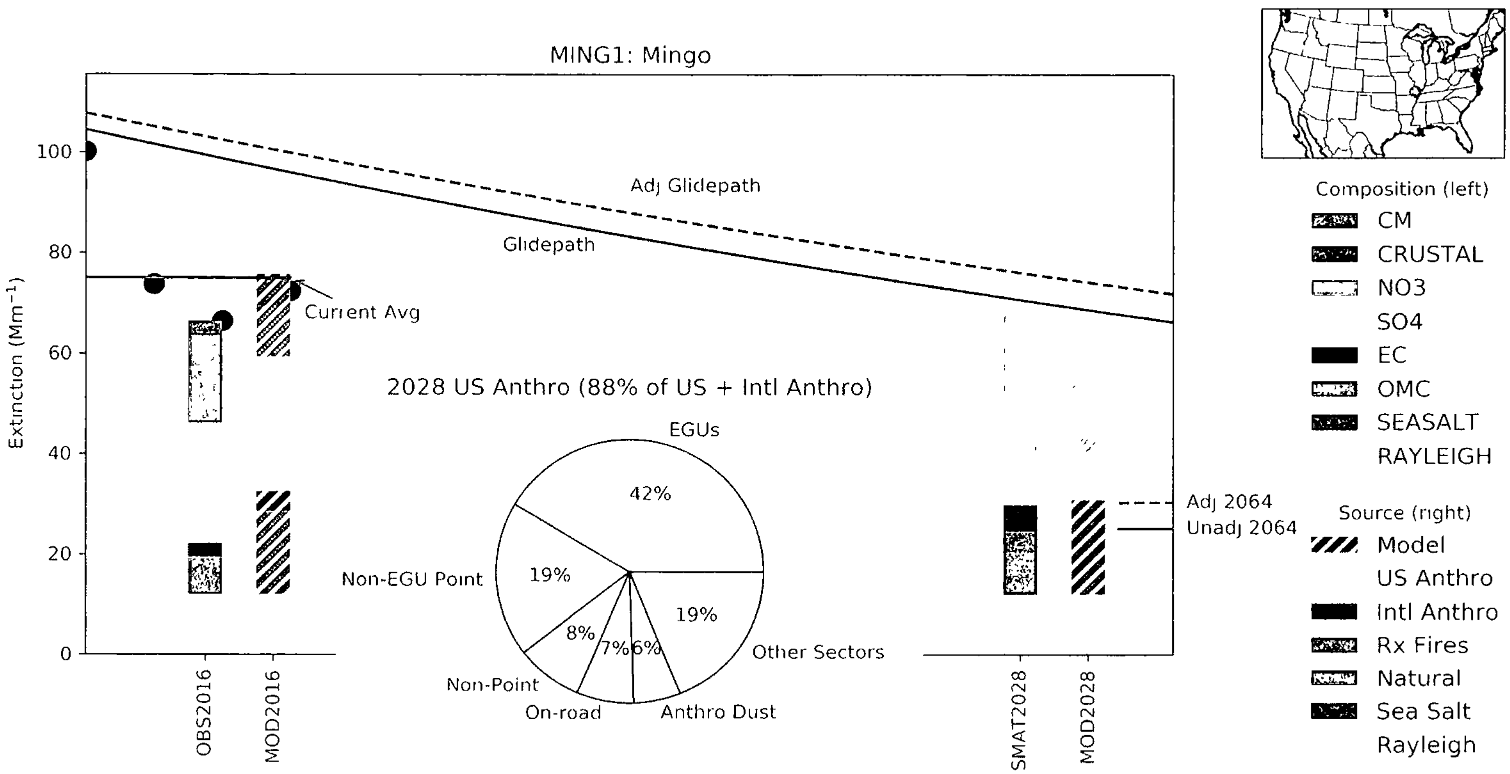

Figure 53: 2014-2017 IMPROVE observations, 2016 CAMx model predictions, 2028 modeled projection, and 2028 sector contributions at MING1. Used for Class I areas: Mingo.

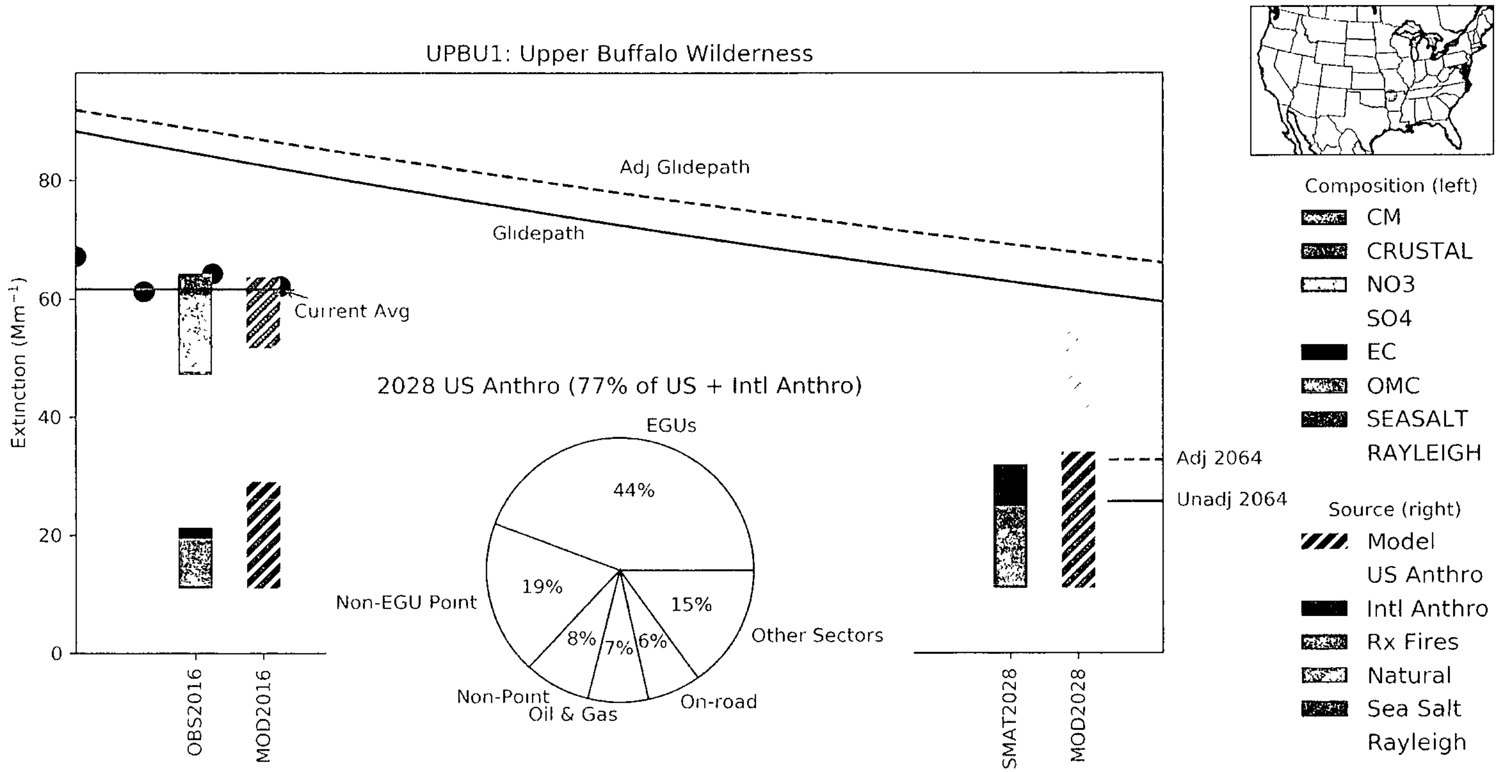

Figure 93: 2014-2017 IMPROVE observations, 2016 CAMx model predictions, 2028 modeled projection, and 2028 sector contributions at UPBU1. Used for Class I areas: Upper Buffalo Wilderness.

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WELSH PLANT BART AND REASONABLE PROGRESS VISIBILITY MODELING

Privileged and Confidential – Prepared at the Request of Counsel

June 20, 2016

BOUNDLESS ENERGY

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INTRODUCTION – BART and REASONABLE PROGRESS

- A number of modeling scenarios have been examined for the Welsh Plant in light of the proposed USEPA BART FIP and to a lesser degree the previously issued Reasonable Progress FIP
- To examine the impact of various scenarios compared to BART, BART was considered to be a DFGD operating at "Presumptive BART" emission rate found in the BART Rule (0.15 lb/MMBtu SO_2).
- NO_x was not considered in this analysis based on USEPA's position that NO_x was being adequately regulated to qualify as BART via other rules (CSPAR).

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INTRODUCTION – BART and REASONABLE PROGRESS

- Defining Reasonable Progress is more difficult, but at 81 FR 303 USEPA indicates that there are similarities between BART and Reasonable Progress causing USEPA to use the BART guidance in formulating their Reasonable Progress FIP
  - Using this logic, purely for comparison purposes in modeling, we have assumed baseline Reasonable Progress reductions are equivalent to Presumptive BART emission rate levels, without regard to economic or other considerations
- The modeling analyses shown in the presentation were performed using the Regulatory version of the CALPUFF Model in accordance with IWAQM and FLAG Guidelines for Visibility Modeling
  - Recommend limiting the use of the model to 300 km from the source
- The analysis of Welsh Plant was limited to the Caney Creek Wilderness Area as it was the only Mandatory Class I Area within 300 km of Welsh

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What Were Baseline Visibility Conditions and the Glide Slope

- Visibility data is based on monitoring by the IMPROVE Network
- Virtually all Mandatory Class I Areas have at least one IMPROVE Monitor
- The data is aggregated and released through the Cooperative Institute for Research in the Atmosphere (CIRA), operated by Colorado State University

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What Were Baseline Visibility Conditions and the Glide Slope

- The Baseline Design Value for Caney Creek is 26.7485 deciviews
  - Deciviews are a measure of obscuration of a vista
  - The Baseline and Target values are based on the average of the 20% worst days of the year
- The 2064 Target for Caney Creek is 11.5104 deciviews
- In 2015 the measured value for the worst 20% days at Caney Creek at Caney Creek was 20.41 deciviews
  - This is approximately 3 deciviews below the uniform rate of progress line
- Being below the uniform rate of progress line is not sufficient justification for not continuing to make "reasonable" emission reductions
  - May be able to be used in the determination of what is a reasonable reduction
  - USEPA will have final say on reasonableness
- If the additional reductions in the emission inventory that will naturally occur over the next few years would be deemed acceptable for Reasonable Progress, it would take the current conditions until approximately 2028 to reach the uniform rate of progress line

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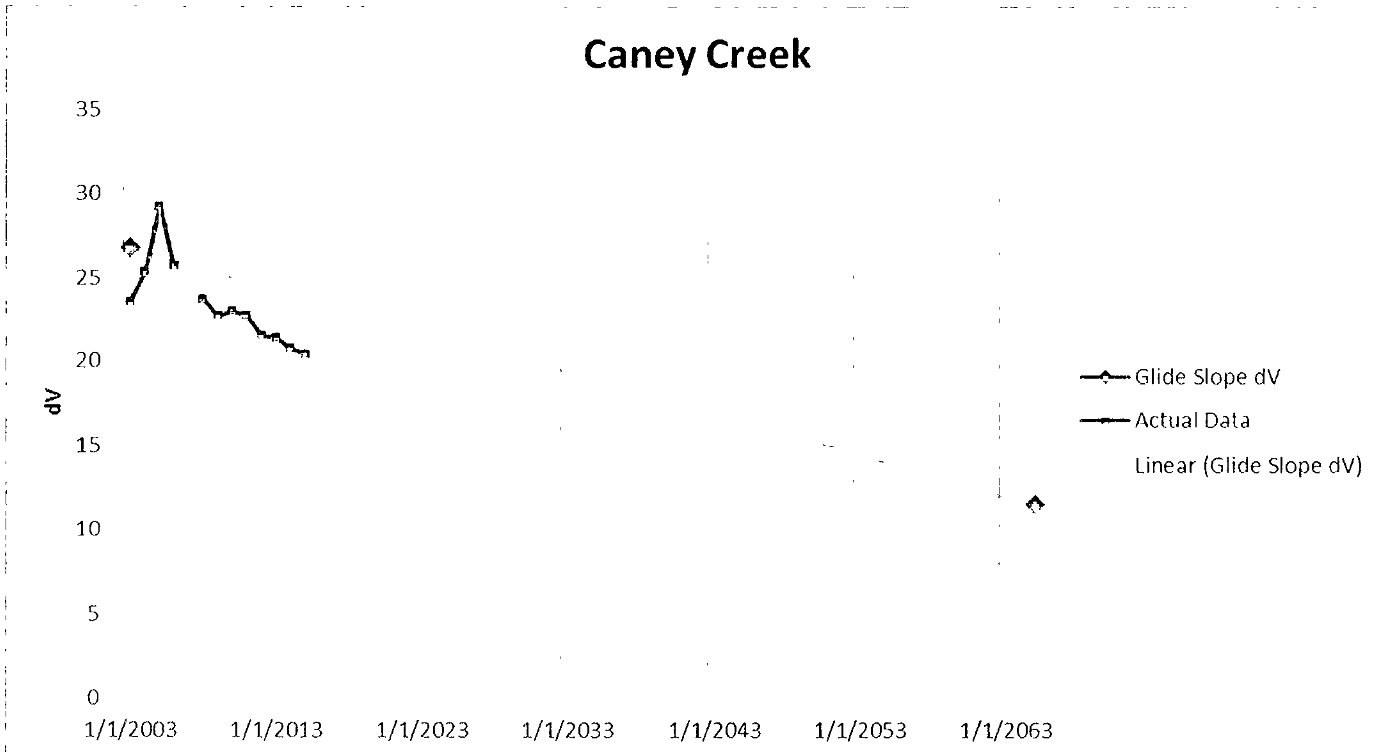
Caney Creek Glide Slope and Actual Data for 2004 to 2015



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Control Scenarios Examined

- We examined several different general scenarios as part of this study
  - A UNIT 1 BART Only Case where only Unit 1 was examined.
    - This is similar to the material presented in USEPA's BART TSD
  - A BART Case examining BART eligible Units 1 and 2, but not considering Unit 3
  - A Plant Wide Case where Units 1 & 2 are under BART and Unit 3 is given emission controls under the Reasonable Progress program

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EPA Analysis Reprise Unit 1 Only Cases With Corrections to EPA Inputs

Metric	Unit 1 Only Base Case Correcting EPA Stack Parameters	Unit 1 Only New GEP Stack Base Case	Unit 1 GEP Stack with 50% Red	Unit 1 New Stack WFGD
SO_2 Emissions @ Full Load (lb/hr)	4656.83	4656.83	2328.41	372.55
NO_x Emissions @ Full Load (lb/hr)	1532.25	1532.25	1532.25	1532.25
2001 Max dv	3.604	3.552	2.476	1.657
2001 Days > 0.5 dv	57	52	29	19
2001 Days > 1.0 dv	21	21	10	4
2002 Max dv	2.032	1.619	1.170	1.339
2002 Days > 0.5 dv	39	37	22	11
2002 Days > 1.0 dv	9	9	4	2
2003 Max dv	2.236	2.960	2.124	1.217
2003 Days > 0.5 dv	53	47	31	14
2003 Days > 1.0 dv	12	16	6	3

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What does the Unit 1 Only Case Show Us

- While these cases don't tell us much, there is at least one notable point
  - Increasing the stack height from 300 ft to GEP reduces the visibility impacts of Welsh on Caney Creek
  - However, we would not see this in a \$/Ton analysis since the emissions remained unchanged
  - If a \$/dv Analysis were performed, there would be a measurable benefit

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BART Only Units at Welsh
What Options Might be Better than BART

Metric	Unit 1 & 2 Base Case	Unit 1 & 2 Presumptive BART Orig Ht DFGD (0.15 lb/MMBtu)	Unit 1 & 2 Presumptive BART GEP Height DFGD (0.15 lb/MMBtu)	Unit 1 Only New GEP Stack Case Unit 2 Retired
SO_2 Emissions @ Full Load (lb/hr)	9921.33	1575.0	1575.0	4656.83
NO_x Emissions @ Full Load (lb/hr)	4086.92	4086.92	4086.92	1532.25
2001 Max dv	6.944	4.327	4.097	3.552
2001 Days > 0.5 dv	109	71	74	52
2001 Days > 1.0 dv	62	35	36	21
2002 Max dv	4.378	3.211	2.876	1.619
2002 Days > 0.5 dv	97	62	62	37
2002 Days > 1.0 dv	43	22	20	9
2003 Max dv	4.661	3.694	3.386	2.960
2003 Days > 0.5 dv	114	75	67	47
2003 Days > 1.0 dv	57	29	27	16

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BART Only Units

- We start to see the differences resulting from the retirement of Unit 2 in this scenario where Unit 3 is ignored.
- With Unit 3 ignored, the retirement of Unit 2 results in better air quality metrics than imposing BART on both units and allowing Unit 2 to remain in operation
  - This observation does not take cost into account

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BART + Reasonable Progress
The Potential Texas Solution
What Options May Be Better

Metric	Units 1, 2, and 3 Base Case	Unit 1 & 2 Presumptive BART GEP Height DFGD + Unit 3 at 12-16 Base	Unit 1 & 2 Presumptive BART/GEP Unit 3 RP (BART)/GEP	Unit 1 & 3 with New Stack and Current Fuel + Unit 2 Retired	Unit 1 & 3 with New Stack and 30% DSI + Unit 2 Retired
SO_2 Emissions @ Full Load (lb/hr)	14961.03	5341.7	2362.5	6833.90	4783.73
NO_x Emissions @ Full Load (lb/hr)	5595.5	5595.5	5595.5	2947.10	2947.10
2001 Max dv	8.972	6.263	5.351	5.361	4.552
2001 Days > 0.5 dv	132	106	94	95	82
2001 Days > 1.0 dv	89	63	55	40	30
2002 Max dv	5.757	3.882	1.3822	2.456	2.177
2002 Days > 0.5 dv	118	90	79	67	62
2002 Days > 1.0 dv	66	46	34	29	23
2003 Max dv	6.165	5.268	4.465	4.292	3.694
2003 Days > 0.5 dv	141	101	87	88	70
2003 Days > 1.0 dv	89	53	38	37	31

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BART + Reasonable Progress

- This portion of the analysis likely represents the most realistic case
- We find that the existing Unit 2 Retired condition has roughly the same benefits as imposing BART on Units 1 and 2 and Presumptive BART on Unit 3 for Reasonable Progress purposes
  - Potential support for allowing Welsh to use the Retirement of Unit 2 to cover the imposition of Controls on Units 1 and 3
  - If this were accepted to cover Welsh's needs for BART and Reasonable Progress, there is little if anything left to potentially trade to Pirkey
- To cover Pirkey, it would likely require as a minimum the installation of DSI at Welsh
  - Taking Pirkey from a baseline case (EPA Method of Calculation) of 7705.14 lb/hr to a Reasonable Progress Control Case results in an SO_2 reduction to 6148.56 lb/hr (1556.58 lb/hr reduction)
  - How this would change the impacts on Caney Creek has not been evaluated at this time.
  - A trade of this nature would be sensitive to the cost of operating at a higher control rate or upgrading the existing FGD at Pirkey vs the cost of installing the DSI equipment and the approval of both Texas and USEPA

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What Can We Draw From This Data at This Time

- As was suspected, there is a definite NOx signal in the data
  - 0.6 Ton of NO_x is equivalent to about 1 Ton of SO_2 in visibility impairment potential from Welsh Plant at Caney Creek based on the peak deciview values
  - Pirkey has not been evaluated for interpollutant or between site trading as part of the work done to date
- The Unit 2 Retired case is roughly equivalent to the Presumptive BART/Reasonable Progress (Presumptive BART) case for Welsh Plant alone
  - Without additional SO_2 reductions beyond the existing case, there is nothing left to use to try to offset Pirkey or Oklaunion under a BART/Reasonable Progress scenario

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What Can We Draw From This Data at This Time

- In order to show that reductions at Welsh would cover any reasonable progress obligations assigned to Pirkey, it would likely require implementation of the 30% DSI Reduction Case on both Units 1 and 3
- While Caney Creek is well under the glide slope, Reasonable Progress is primarily a cost effectiveness evaluation, that would require a showing that doing nothing more than what has been done at Welsh was the most cost effective option under a BART/Reasonable Progress Scenario.
- A trading scenario, if shown to be equivalent in its effectiveness, would likely result in a lower cost scenario.
  - Trading scenarios have not been evaluated under this study to date

Privileged and Confidential – Prepared at the Request of Counsel

**Response of Southwestern Electric Power Company
to the Arkansas Department of Energy & Environment
Division of Environmental Quality
Information Request Regarding Candidate Technologies
For John W. Turk (Turk Plant) Unit 1**

1) <u>Neural Network/Intelligent Sootblower System Information</u>:

a) **Please indicate whether each unit listed above is tied in to a neural network system to optimize the unit's operations and minimize emissions.**

Turk Unit 1 does not utilize a neural network system for combustion optimization or any other operational system. Turk Unit 1 utilizes a Distributed Control System (DCS) and Process Information (PI) monitoring systems to provide the unit operators with a full view of the critical operating conditions on the unit. Sensors monitor temperatures, pressures, heat rate deviations on certain subsystems, various alarms, and certain market-based conditions. In addition to optimizing steady state operations, these sensors and related controls allow unit operators to make necessary changes in real time when the unit is required to change loads in response to automatic generator control by the regional transmission operator.

There is also a centralized Monitoring and Diagnostic Center (MDC) available to the AEP system units, which has the capability to monitor and trend individual data points remotely in real time, spot early trends, and proactively recommend actions to improve performance or eliminate a curtailment before costly damage occurs. Based on the information available through these systems, operators are able to distinguish between controllable and uncontrollable factors impacting heat rate on the unit, and take prescribed actions to reduce the impacts associated with controllable factors as much as physically and economically possible. Intensive operator training, including the use of a centralized control system generator simulator during that training, provides our personnel with the knowledge necessary to initiate appropriate changes in operating parameters, and monitor the effects of automated responses in certain supplemental control systems, to assure that stability is achieved and maintained during all operating conditions

i. If a unit is tied in to a neural network system,

1. When was the neural network first operated?

Not applicable

2. What impact did this have on your heat rate?

Not applicable

ii. If a unit is not tied in to a neural network system and the technology is feasible,

1. Please quantify the cost to implement a neural network system for your unit.

As described above, there are presently sophisticated control systems, instrumentation and monitoring resources available to maintain stable and efficient control of the combustion process and other unit operations without the use of "neural network" technology While it would be feasible and expensive to install additional sensors, optimizers and control systems which are available on the market today, the degree of improvement that could be achieved through this investment is not expected to achieve the levels identified in Table 1 of the ACE Rule. Turk Plant has not solicited any specific pricing for such a system, but has no reason to believe the cost would be significantly different that that listed in Table 2 of the ACE Rule

2. Please quantify the expected heat-rate impact of implementation of a neural network system.

The opportunity for heat rate improvements with this technology is measured as a reduction of the typical heat rate increase that occurs over a long period of operating time. It is not an improvement in the design heat rate of the unit. In addition, the sensors, information, and controls must also be accompanied by actions necessary to make meaningful change in performance While a neural network can expand the data points that are measured and monitored, it ultimately requires actions by both programmed control systems and experienced operators to start/stop and verify equipment operation or modify control settings to make meaningful change in performance. Turk Unit 1 is a very modern unit, designed and installed with integrated components and control systems, managed by experienced operators and which achieves a heat rate which is one of the lowest of all coal-fired generating units Since heat rate deviation from design has historically been very low for Turk Unit 1 during its 8-year operating life thus far, addition of a neural network would result in only a marginal improvement that is less than the range predicted in Table 1 of the ACE Rule.

iii. If the technology is not technically feasible or is limited, then please provide a detailed explanation of why the technology is not technically feasible or is limited due to the unique characteristics of each unit.

Although technically feasible, the benefits of applying of this technology are limited for the reasons discussed above.

b) Is an intelligent soot blower system operated for any of the units listed above?

Turk Unit 1 is equipped with an intelligent sootblowing system that was installed with the original unit construction and went into service in 2012. The sootblowing system that was installed is a Sentry Series system which is a product of Diamond Power Company. The system also uses a B&W Power Clean heat flux monitor to assess conditions within the furnace and send commands to the sootblower control system.

i. If an intelligent soot blower system is operated for the unit, then please respond to the following questions:

1. Is the intelligent soot blower system incorporated into the neural network software? If so, does the impact you specified for 1)a)i.2. include the impact of the intelligent soot blower system?

No, this unit does not use a neural network for combustion or sootblower control. The sootblowers have the ability to be automatically controlled via the supplied control system or via manual override by unit operators as may be needed.

2. If the intelligent soot blower system is not incorporated into a neural network software package, then please respond to the following:

a. **When was the intelligent soot blower system first operated?**

The Diamond Power Co intelligent soot blower system was installed new with the original construction and was put into service with original commissioning of the unit in 2012 The existing sootblowing system performance model and configuration controls will be replaced with a Babcock & Wilcox Co. (B&W) ISB Titanium System in Spring 2020.

b. **What impact did this have on your heat rate?**
Performance measurements to determine the impact of the sootblower systems on unit heat rate were not taken These systems were installed primarily to reduce the risk of slag formation and potential unacceptable accumulation of ash on the heat transfer surfaces. Any heat rate "improvement" that is realized from these systems is in effect a reduction of the heat rate penalty being experienced against the unit design because of ash/slag buildup. These do not effectively improve the heat rate beyond the original design basis for a "clean" boiler, but when used effectively can maintain heat rate closer to the design value for a longer period of time

ii. If an intelligent soot blower system is not operated for the unit and is technically feasible, then please respond to the following:

1. Please quantify the cost to install an intelligent soot blower for your unit.

Not Applicable

2. Please quantify the expected heat rate impact of the intelligent soot blower system.

Not Applicable

iii. If the technology is not technically feasible or is limited, then please provide a detailed explanation of why the technology is not technically feasible or is limited due to the unique characteristics of each unit.

Not Applicable

c) **Please provide any other information relevant to DEQ's analysis of this candidate technology.**

Neural Network (NN) technology was developed and applied on a "test" basis to some steam generator equipment at other AEP units a decade ago. Reported results of the very controlled tests were highly variable and the technology focused on mainly one aspect (fuel-air distribution within the furnace) of the steam generation process. Testers concluded that the technology did not provide sufficient economic benefit to apply at full scale. Since that time, the implementation of the Mercury and Air Toxics Standards (MATS) rule has introduced increased regularity into the inspection, repair, and tuning of combustion controls. In addition, NN technology still requires manual coordination of several other processes, including starting and stopping large equipment such as pulverizers and fans, in order to maintain combustion stability within the steam generator SWEPCO relies on well-trained and highly knowledgeable operators to perform this integrated control in a highly efficient and reliable manner without the use of NN's. The current use of the sootblowing system on Turk Unit 1 maintains a high level of steam generator cleanliness and no measureable additive heat rate improvement is anticipated to result from integrating a neural network for this unit

2) **Boiler Feed Pumps:**

Large electric motor powered boiler feed pumps (BFPs) supply feedwater to the steam generator in some units, and are responsible for a large portion of the auxiliary power consumed within a power plant (up to 20 MW from a 600 MW unit). Rigorous maintenance is required to ensure reliability and efficiency are maintained Wear reduces the efficiency of the pump operations and requires regular rebuilds/upgrades/overhauls. These improvements for electric boiler feedwater pumps reduce auxiliary power demands and improve *net* heat rate, but would not result in measureable improvements in *gross* heat rate.

At Turk Unit 1 the main boiler feed pump is driven by a steam turbine and not by an electric motor As such, for most of the operating range of Unit 1 (above 30% output), the boiler feed pump is self-regulating and matches the steam needed to the load at which the unit is operating. In addition, it enhances the overall efficiency of the unit because of the reduced auxiliary electric demand (a reduction of as much as 35% of typical auxiliary load) For startup and low load operation, where there is insufficient steam yet available to supply the auxiliary drive steam turbine, a smaller motor-driven feed pump is used to provide the required feedwater. This pump is initially used during unit startup on the steam bypass system and prior to the electric generator producing any output and is removed from service at approximately 30% load. Boiler feed pump turbines can experience degradation and wear over time, and require periodic maintenance to repair turbine blades, exchange rotors, and restore steam seals. At Turk Unit 1, a regular turbine overhaul is planned approximately every 10 years, or after 80,000-100,000 hours of service Given that the original design of this unit includes a more efficient technology for use above startup flow conditions, and the operator has adopted a regular schedule for overhauls of the pump and turbine, it is reasonable to conclude that no incremental improvement is currently achievable

a) Over the past year, how does the performance of the boiler feed pumps for each unit compare to the manufacturer specifications?

The pump design is highly efficient and robust to withstand the rigor of numerous years of continued service with very little O&M required. The pump also maintains its efficient performance for the duration of the period between overhauls. During the past year, the feed pump has performed within the design specifications

b) When was the last time the boiler feed pump(s) for each unit was overhauled or upgraded?

The main turbine-driven boiler feed pump was last overhauled and rebuilt in 2015 as a precautionary measure following an operation event (water hammer) which resulted in unusual pipe movement The pump was found to be in acceptable condition but was rebuilt with an available new spare internal assembly. The startup motor-driven feed pump accumulates limited operation time and has not yet reached the service hours recommended for overhaul

c) If the boiler feed pumps have not been overhauled or upgraded in the period or at the performance characteristics recommended by the manufacturer specifications,

i. Please quantify the cost to overhaul or upgrade the boiler feed pump(s) for your unit.

Not applicable. The last overhauls were within specifications and within the performance period.

ii. Please quantify the expected heat rate impact of overhauling or upgrading the boiler feed pump(s).

Not applicable. Maintenance overhauls are performed on the feed pumps in order to maintain their capacity to perform reliably and uninterrupted during the operating periods. Any degradation is unlikely to achieve the amount that is projected within Table 1 of the ACE Rule. The internal condition of the pump must be maintained within manufacturer's specification in order to avoid operational failure and a forced outage.

iii. Please provide any other information relevant to the DEQ's analysis of this candidate technology.

Ultra-supercritical units using a single 1x100% capacity pump are not commonplace in the industry and thus the OEMs do not offer much in the way of efficiency improvements. AEP is not aware of any advanced designs for a steam-driven or electric motor driven boiler feed pump that could provide a heat rate improvement of 0.2%-0.5% above this unit's current performance as set forth in Table 1 of the ACE Rule

d) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.

The boiler feed pumps at this unit have been regularly maintained in accordance with manufacturer's specifications and additional overhauls are unnecessary.

3) <u>Please specify whether the air pre-heater for each unit listed above is regenerative (rotary) or recuperative (tubular or plate)</u>.

The two (2) air pre-heaters installed on Turk Unit 1 are tri-sector regenerative air heaters which do rotate.

a) If your unit has a regenerative air pre-heater, when were the seals last replaced?

The air heater seals were installed new as a complete set in 2012 when the unit was initially built and commissioned. Seals are inspected and maintained on an annual basis during maintenance outages as recommended by the air heater OEM The sector plates are also inspected and have been found to be performing as per specification This maintenance can include repairs to sealing components or replacement of partial sets of seals as necessary, based on damage or wear.

b) If the seals have not been replaced in the period or at the performance characteristics recommended by the manufacturer specifications,

i. Please quantify the cost to replace the seals for the regenerative air pre-heater for your unit

As discussed above, the seals are inspected and maintained in accordance with the manufacturer's recommendations during regular outages. The costs for these inspections and repairs have not been separately tracked

ii. Please quantify the expected heat-rate impact of replacing the seals.

The impact is very marginal since only partial set repairs or replacement are typically necessary due to extent of damage or wear. Continued replacements in accordance with past practice will allow the unit to maintain its historic efficiency.

c) **Please provide any other information relevant to DEQ's analysis of this candidate technology.**

The improvement projected from this technique (upgraded air heater seals) results from limiting air in-leakage on regenerative air heaters by replacing air heater seals with newer designed low-leakage seals. Most units have some rate of air in-leakage, which can result in higher demand on the fans that provide air to the combustion zone in the boiler and higher auxiliary power demands.

For this unit, air heater seals are typically inspected, repaired or replaced with in-kind seals during equipment outages when the air heater baskets are replaced or when seals are found damaged Additionally, the air heater internal ducts and sector plates are inspected during maintenance on the air heater, and localized repairs and stationary seal replacements can be made during those inspections if materials are available, or included in future outage plans. This unit is equipped with adjustable sector plates which provide for a more uniform seal throughout the temperature excursions caused by various unit load conditions.

There are products on the market that advertise lowering the amount of leakage experienced within air pre-heater equipment. While it is likely feasible to install such products on Turk Unit 1, it is currently AEP's opinion that the newer designs for low-leakage seals present risks to unit reliability and air heater functionality that may outweigh any efficiency gains. A thorough technical review is needed to determine applicability and potential benefits for Turk Unit 1. Plant operators currently use PI system screens for monitoring differential pressure, temperatures and flue gas pressure in the air heater and motor amps for the PA, FD and ID fans in order to assess air heater loading and performance. Application of the low-leakage seal design would require some level of detailed engineering and design by the boiler and/or air heater OEM(s) to determine a suitable method of application and to determine the potential benefits to be gained and reliability risks to consider in each specific case. A feasibility study has not been performed for this unit Some leakage at this location is necessary to avoid air heaters "locking up" (not being able to rotate) which can lead to malfunctions, curtailments, or availability problems.

d) **Please provide a detailed explanation if the technology or practice is not technically feasible or limited due to the unique characteristics of the unit.**

See response to item c) above.

4) Variable Frequency Drives (VFD) information for each listed unit:

Variable Frequency Drives are available that work in concert with traditional electric motors to vary the speed necessary during unit load changes to maximize performance of the driven equipment and reduce losses. This results in a reduction of power consumption as an auxiliary load and helps to maximize the net electrical generation from the unit. The most effective applications are for electric driven boiler feed pumps that control feed water flow and induced draft fans that control air/gas flow through the flue gas path.

At Turk Unit 1, approximately 65 percent of the electric demand on a typical unit has already been addressed, including both of the major applications for VFDs identified in the ACE rule. First, the main BFP is driven by an auxiliary steam turbine that automatically adjusts to the required load and does not consume electricity. This pump/turbine combination is placed in service when the unit advances off of the startup system and achieves approximately 30% output and remains in service up through full load Second, induced draft fans were provided on this unit during original construction and are axial flow fans with variable blade vane pitch, which reduce energy losses, enhance operator control, and increase volumetric flow through the unit to increase efficiency. The axial vane fans deliver substantially similar benefits as VFDs. In fact, in its 2009 report on coal-fired power plant heat rate reductions, Sargent & Lundy compared the benefits of centrifugal fans with VFDs to axial vane fans, and determined that the axial vane fans provided slightly superior performance *Coal-Fired Power Plant Heat Rate Reductions*, Sargent & Lundy, Final Report on Project 12301-001 (Jan 22, 2009) at p.8-5.

a) **Does your unit have VFD controls for the induced draft (ID) fans?**

No

i. If so,

1. When was the VFD first operated?

Not Applicable

2. What impact did this have on your heat rate during base-load and cycling operating scenarios?

Not Applicable

ii. If not,

1. Please quantify the cost to install and operate a VFD for the ID fans for your unit.

As mentioned in the paragraph above, Turk Unit 1 was able to install axial vane variable flow fans with conventional single speed motors for the induced draft fan applications when the FGD equipment was installed as part of original construction in 2012. SWEPCO does not have a true cost for adding a VFD onto an existing induced draft centrifugal fan Power differential to operate the axial vane fans versus a conventional centrifugal fan and motor with VFD is negligible

2. Please quantify the expected heat-rate impact of the installation and operation of VFD for ID fans for both base-load and cycling operating scenarios.

Based on the Sargent & Lundy report, SWEPCO anticipates that any difference would be negligible

b) **Does your unit have VFD controls for the boiler feed pumps?**

No. As mentioned in Question 2 (Boiler Feed Pumps) above, the single main boiler feed pump is driven by a steam turbine. The auxiliary startup boiler feed pump is driven by an electric motor.

i. If so,

1. When was the VFD first operated?

Not applicable

2. What impact did this have on your heat rate during base-load and cycling operating scenarios?

Not applicable

ii. If not,

1. Please quantify the cost to install and operate a VFD for the boiler feed pump(s) for your unit.

Application of a VFD to the auxiliary boiler feed pump drive motor would likely be cost prohibitive since the motor is approximately 5,000 HP, operates for a limited time only during startup when feed water flow is low and controlled by a regulating valve, steam components are being warmed from the bypass system and the electric generator is not connected to the grid (except for a limited period of time when the unit is producing less than 30% of rated MWs) This period would likely not be part of the emissions performance standard period of testing.

2. Please quantify the expected heat rate impact of the installation and operation of VFD for the boiler feed pump(s) for both base-load and cycling operating scenarios.

The impact of adopting a VFD to the auxiliary boiler feed pump motor would be extremely low, well below the suggested range offered in ACE Rule Table 1, as this motor is infrequently used and likely produce unmeasurable benefits.

iii. Please provide any other information relevant to DEQ's analysis of this candidate technology.

Because there is no electrical load consumed by the boiler feed pump over the majority of this unit's operating range (all loads above 30%), the design of the axial vane fans provide similar efficiency benefits, and the small motor used during start up operates only at low loads and infrequently, any benefits from applying VFDs would be well outside the range estimated by EPA and would not be cost-justified

c) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.

See response to item b)iii , above

5) Blade Path Upgrade (Steam Turbine) for each listed unit:

The best candidates for blade path upgrades are those turbines experiencing steam leaks and blade erosion, where efficiency improvements can be achieved using computerized flow modeling and innovative materials. However, there is significant variation among units. These upgrades are large capital investments and require long lead times.

Turk Unit 1 is equipped with one high pressure turbine, one intermediate pressure turbine and two low pressure turbines. The turbine blade path was designed and manufactured to modern, efficient standards of the industry and was state-of-the-art when constructed and commissioned in 2012. This unit is unique on the AEP system No spare turbine rotors exist so all components are either repaired or replaced if necessary during maintenance inspections.

a) Has the steam turbine for the unit been upgraded or overhauled in the past ten years? If so,

i. When was the turbine upgraded or overhauled?

Not applicable since the turbine has not been upgraded or overhauled to date

ii. Describe how the turbine was upgraded or overhauled.

Not Applicable

iii. How did the upgrade or overhaul impact the unit's heat rate?

Not Applicable

iv. Are there further upgrades available that would improve the efficiency of the turbine?

None known The degree to which the existing turbine blade path deteriorates or wears over time and service conditions will not be known until the initial turbine inspections are performed Since the original blades were designed and manufactured to modern standards, it is not expected that significant incremental improvement in efficiency would be available with an upgrade. Only recoverable losses could be gained by performing the turbine overhaul and repair.

b) If not,

i. Please quantify the cost to upgrade or overhaul the steam turbine for your unit. (You may factor the costs associated with new source review, if it would be triggered by the upgrade, into your cost calculations.)

The steam turbine on Turk Unit 1 has not been upgraded in the first 8 years of its operating life since initial startup in 2012. In fact, no section of the steam turbine has yet undergone its initial opening and inspection (overhaul) which is currently scheduled for 2023

Cost information for specific overhaul or upgrade projects is considered Confidential Business Information and is not included in this document. Budgetary information related to the future overhaul of the Turk Unit 1 turbine sections will be prepared in advance of the scheduled outage and will reflect that which is typical for turbines supplied by this specific OEM, including like-kind replacement of any worn or damaged parts. There has been no information gathered as of this time related to a potential upgrade of the steam turbine blade path on Turk Unit 1.

ii. Please quantify the expected heat rate impact of upgrading or overhauling the steam turbine.

No information related to improvements available from a turbine blade path upgrade is available for Turk Unit 1 The initial turbine overhauls are expected to produce opportunities to restore the turbine section efficiencies to near design condition, except for any damage mechanisms that result in non-recoverable losses (e g casing/seal distortion or inter-stage steam leaks) Such heat rate improvements are expected to fall in the lower end of the expected range of Table 1 in the ACE Rule.

c) Please provide any other information relevant to DEQ's analysis of this candidate technology.

Steam path inspections are performed during scheduled outages when turbine overhauls will allow for any liabilities to be addressed and for replacement parts to be procured and made ready for installation. There are no known current upgrade offerings that may be available for the turbine sections at Turk Unit 1. Any offerings in the future would need to be evaluated prior to commitment, forecasting of funds, procurement and implementation. The next regular maintenance opportunity for the turbines on Turk Unit 1 is currently scheduled for 2023.

d) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.

Please see the responses to items b) and c), above. Also, incremental improvement of any blade path upgrade is likely not economically justified based on modern design of currently installed blades.

6) <u>Economizer for each listed unit</u>

Replacing or redesigning the economizer can optimize temperatures at the exit of the boiler. Boiler layout and construction may limit the applicability of this measure to certain units.

a) When was the economizer last replaced?

The economizer on Turk Unit 1 is original and has never been replaced On occasion, there has been a need to locate and access certain areas of the economizer to address leaking tubes or other physical damage. This repair could result in replacement of a small number of tubes or partial tube sections but no major replacement of tube bundles has been necessary.

b) Throughout the past year, how does the performance of the economizer for each unit compare to the manufacturer specifications for a new unit?

During the past year, the economizer on Turk Unit 1 has performed well, allowing for critical temperatures such as boiler exit gas and air heater gas outlet temperatures to remain within manufacturer specifications throughout the load range.

c) If the performance of the economizer for a unit has degraded outside the performance range of the manufacturer's specifications:

i. Please quantify the cost to redesign/replace the economizer for your unit.

Not applicable

ii. Please quantify the expected heat-rate impact of redesigning/replacing the economizer.

Not applicable

d) Please provide any other information relevant to DEQ's analysis of this candidate technology.

Because there are currently no issues with the performance of the existing economizer, and no specific design changes have been identified that would allow the unit to increase efficiency without potentially compromising the operation of downstream equipment, there are no known changes to evaluate, and no heat rate improvement is anticipated to be associated with an economizer redesign/replacement project

e) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.

It is technically feasible to replace an economizer either with like-kind design or with some improvements in materials or heat transfer characteristics. Limited like-kind replacements of economizer sections have been made to repair tube damage with no impact to the heat rate of the unit However, making changes to the economizer design or replacing the economizer in its entirety would have significant impacts on downstream equipment at this unit, including the SCR catalyst and the air heaters, which are sensitive to flue gas temperature changes The existing economizer is functioning well in its current cycle and condition and does not warrant replacement.

7) <u>Heat Rate Improvement Practices</u>

a) Do the staff at the plant where the unit is located undergo routine training that would positively affect the heat rate of the unit or units? (Such training may include any training related to efficiency or any other training on practices that result in heat rate improvements.)

Heat rate improvement "awareness training" is suggested as a means of elevating awareness of specific heat rate improvement efficiency measures among the operations and maintenance staff at units including Turk Plant affected by the rule In the response to ACE Rule comments, EPA recognized that the level of awareness at individual units could vary dramatically, and that states might simply take into consideration whether there are existing programs at specific units as part of the overall evaluation of the candidate technologies Capital costs are anticipated to be minimal and the impact of implementing new or existing programs is difficult to estimate and expected to be widely variable.

As generating units across the country have joined regional transmission organizations and begun offering the output of their units into competitive generation markets, cost-effective operation of individual units has become increasingly important. AEP units in the west are dispatched as part of SPP (Southwest Power Pool) which has a robust day-ahead energy market. As a result, increasing attention has been focused on ways to improve efficiency and lower operating costs

i. If so, describe the training program including frequency of training and practices taught.

AEP provides training, monitoring tools, and "best practice" sharing forums for its employees as a way to help plant operators and staff to improve their awareness and equip them with means to maintain efficient operations and identify further efficiency improvements Some of these tools and practices include.

- Operator training
- HRI classes, focusing on plant system optimization, are held at the Generation unit simulator center in St. Albans, WV and periodically attended by SWEPCO / Flint Creek personnel
- An automated Monitoring & Diagnostics Center

- Equipment control systems capable of automatically responding to changing conditions
- Regular technology updates and reviews
- Participating in and contributing to AEP Operational Excellence Program for best practices, including maximizing performance and reducing heat rate
- Maintaining thermal performance models of the unit design cycle with equipment references

The degree to which individual unit operators, supervisors and engineers undergo various parts of this training depends upon their position and desire to further develop and take on additional responsibilities Some positions such as a Control Center Operator (CCO) requires prior successful completion of the NUS Heat Rate course. The CCO is also responsible to monitor "controllable" heat rate monitor screens in the unit control room to aid in determining the most efficient unit operation conditions for Turk Plant

ii. If not,

1. Please provide to DEQ a plan for instituting such a program.

Not applicable since AEP already conducts such a program for Turk Plant operators

2. Quantify the annual costs of implementing a program.

Not available on a specific unit or plant basis as this is part of continual learning within the AEP System

3. Quantify the expected heat-rate impacts of implementing a program.

Existing programs and measures are currently being employed and improvements are reflected in the historic emissions data for this unit The precise percentage in unknown No quantifiable incremental increase in heat rate improvement is anticipated as a result of continuing the existing practices, which include regular technology reviews and updates

b) EPA requires DEQ to consider an "on-site appraisal" of heat-rate improvement opportunities at a specific unit. Please submit a report detailing the results of an onsite appraisal of heat-rate improvement opportunities. This appraisal may be conducted by an internal group or a third-party. Include a summary of the most recent inspection and recommendations for equipment maintenance or replacement to minimize heat-rate deviations, and include actions taken in response to the recommendations

The practices identified in the prior section are tools used to assist unit operators and engineering support personnel on the AEP system in planning regular maintenance, developing the scope of work for planned outages, and designing monitoring or information collection efforts tied to specific equipment issues or unit liabilities. This can in turn allow internal personnel or third parties to be engaged to perform a more in-depth evaluation and assessment of specific ideas for improved heat rate performance Such "appraisals" can be conducted to address issues identified on individual units, or to develop a more comprehensive effort that could be implemented at multiple units with a strategic alignment Several ideas in the past were identified as potential heat rate improvements and collaboratively reviewed between plant staff, M&D Center analysts, AEP Engineering and in some cases an equipment OEM These performance "enhancements" were developed with the intent of lowering pressure drop or stopping undesirable steam leakage flow as a means to improve performance and lower heat rate. Power plant personnel and engineers continually review the performance of various pieces of equipment to look for opportunities to make improvements, solicit necessary funding and outage time, and procure the necessary materials to implement the improvement. Many of these improvements are small and hard to measure individually or at the specific time of change, but continually aid in allowing the unit to perform as efficiently as possible. Current internal efforts are focused on optimizing unit operations at partial loads, or during sustained periods of low-load operation as being dictated by the SPP-controlled marketplace.

c) Does your plant have a routine steam surface condenser cleaning program?

Improved steam surface condenser tube cleaning was selected as a HRI measure that forms part of the BSER by EPA because the efficiency with which steam is condensed back into liquid is a critical part of the thermodynamic cycle. Lowering the temperature in the condenser and having an effective air removal system in operation decreases backpressure on the turbine allowing more efficient expansion in the steam cycle.

Turk Unit 1 main condenser undergoes an annual inspection and cleaning of the tubes each spring. The steam side of the tubes are inspected via physically entering the condenser steam compartment and looking at tube cleanliness and removing any debris The water side condition of the condenser tubes are inspected during maintenance outages and cleaning processes applied as dictated by condition and thermal performance.

i. **If so, describe the impact that this program has on the heat rate of each unit.**

Condenser fouling has not typically been a problem on Turk Unit 1 Performance as indicated by the relationship between cooling water temperature and back pressure achieved during seasonal periods has tracked close to design. It is apparent that the cleaning methods are working and the quality of the cooling water and steam purity in the condensate cycle are being managed at optimum values.

ii. **If not,**

1. **Please provide to DEQ a plan for instituting such a program.**

   Not applicable

2. **Quantify the annual costs of implementing a program.**

3. **Quantify the expected heat-rate impacts of implementing a program.**

d) Please provide a detailed explanation if a practice is not technically feasible or limited due to the unique characteristics of the unit.

Not applicable

e) Please provide any other information relevant to the State's analysis of these practices.

Continuous monitoring of condenser performance for Turk Unit 1 indicates that control parameters regarding water quality and tube pluggage ratio are within acceptable limits. The condensers are performing well throughout the load range and under a variety of seasonal temperature conditions. Thus there is no basis to consider any changes regarding condenser cleaning procedures for this unit.

8) Gross vs net generation standards

a) Would you recommend the standards of performance for each affected unit be established in pounds of carbon dioxide emitted per net megawatt hour or per gross megawatt hour? Explain your recommendation.

The performance standard should be based on gross generation as this is the total generation produced by the unit, and is currently regularly monitored and reported through the Clean Air Markets Division for all units.

b) If your recommendation is for a gross generation-based standard, then do you have any recommendations for accounting for emissions reductions attributable to technologies affecting only net efficiency?

Technologies that impact net efficiency can be transient (impacting only certain load ranges or operating conditions) and difficult to measure. Gross measurements will assure that all conditions and load ranges are adequately measured and reported and there is no requirement to separately account for potential improvements in net efficiency.

**Response of Southwestern Electric Power Company
to the Arkansas Department of Energy & Environment
Division of Environmental Quality
Information Request Regarding Candidate Technologies
For Flint Creek Unit 1**

1) <u>Neural Network/Intelligent Sootblower System Information</u>:

a) **Please indicate whether each unit listed above is tied in to a neural network system to optimize the unit's operations and minimize emissions.**

Flint Creek Unit 1 does not utilize a neural network system for combustion optimization or any other operational system. Flint Creek Unit 1 utilizes a Distributed Control System (DCS) and Process Information (PI) monitoring systems to provide the unit operators with a full view of the critical operating conditions on the unit Sensors monitor temperatures, pressures, heat rate deviations on certain subsystems, various alarms, and certain market-based conditions. In addition to optimizing steady state operations, these sensors and related controls allow unit operators to make necessary changes in real time when the unit is required to change loads in response to automatic generator control by the regional transmission operator

There is also a centralized Monitoring and Diagnostic Center (MDC) available to the AEP system units, which has the capability to monitor and trend individual data points remotely in real time, spot early trends, and proactively recommend actions to improve performance or eliminate a curtailment before costly damage occurs. Based on the information available through these systems, operators are able to distinguish between controllable and uncontrollable factors impacting heat rate on the unit, and take prescribed actions to reduce the impacts associated with controllable factors as much as physically and economically possible. Intensive operator training, including the use of a centralized control system generator simulator during that training, provides our personnel with the knowledge necessary to initiate appropriate changes in operating parameters, and monitor the effects of automated responses in certain supplemental control systems, to assure that stability is achieved and maintained during all operating conditions

i. If a unit is tied in to a neural network system,

1. When was the neural network first operated?

Not applicable

2. What impact did this have on your heat rate?

Not applicable

ii. If a unit is not tied in to a neural network system and the technology is feasible,

1. Please quantify the cost to implement a neural network system for your unit.

As described above, there are presently sophisticated control systems, instrumentation and monitoring resources available to maintain stable and efficient control of the combustion process and other unit operations without the use of "neural network" technology While it would be feasible and expensive to install additional sensors, optimizers and control systems which are available on the market today, the degree of improvement that could be achieved through this investment is not expected to achieve the levels identified in Table 1 of the ACE Rule. Flint Creek Plant has not solicited any specific pricing for such a system, but has no reason to believe the cost would be significantly different that that listed in Table 2 of the ACE Rule

2. Please quantify the expected heat-rate impact of implementation of a neural network system.

The opportunity for heat rate improvements with this technology is measured as a reduction of the typical heat rate increase that occurs over a long period of operating time It is not an improvement in the design heat rate of the unit In addition, the sensors, information, and controls must also be accompanied by actions necessary to make meaningful change in performance While a neural network can expand the data points that are measured and monitored, it ultimately requires actions by both programmed control systems and experienced operators to start/stop and verify equipment operation or modify control settings to make meaningful change in performance Since much of this work is already being achieved on Flint Creek Unit 1 through existing sensors and controls and experienced operators, it is expected that addition of a neural network would result in a marginal improvement that is less than the range predicted in Table 1 of the ACE Rule

iii. If the technology is not technically feasible or is limited, then please provide a detailed explanation of why the technology is not technically feasible or is limited due to the unique characteristics of each unit.

Although technically feasible, the benefits of applying of this technology are limited for the reasons discussed above

b) Is an intelligent soot blower system operated for any of the units listed above?

Flint Creek Unit 1 is equipped with an intelligent sootblowing system that was installed in 2007. The system that was installed is a product of Diamond Power Company.

i. If an intelligent soot blower system is operated for the unit, then please respond to the following questions:

1. Is the intelligent soot blower system incorporated into the neural network software? If so, does the impact you specified for I)a)i.2. include the impact of the intelligent soot blower system?

No, this unit does not use a neural network for combustion or sootblower control. The sootblowers have the ability to be automatically controlled via the supplied control system or via manual override by unit operators as may be needed

2. If the intelligent soot blower system is not incorporated into a neural network software package, the please respond to the following:

a **When was the intelligent soot blower system first operated?**

Water lances were installed prior to 2007 to improve cleaning of the radiant heat area of the furnace. The intelligent sootblower system was installed and put into service in 2007 during a scheduled unit outage. Then in 2016 the system was upgraded to a Diamond Power Sentry Series sootblowing system which included variable steam flow capability and several additional steam sootblowers

b. **What impact did this have on your heat rate?**

Performance measurements to determine the impact of the sootblower systems on unit heat rate were not taken. These systems were installed primarily to reduce the risk of slag formation and potential unacceptable accumulation of ash on the heat transfer surfaces. Any heat rate "improvement" that is realized from these systems is in effect a reduction of the heat rate penalty being experienced against the unit design because of ash/slag buildup. These do not effectively improve the heat rate beyond the original design basis for a "clean" boiler, but when used effectively can maintain heat rate closer to the design value for a longer period of time.

ii. If an intelligent soot blower system is not operated for the unit and is technically feasible, then please respond to the following:

1. Please quantify the cost to install an intelligent soot blower for your unit.

Not Applicable

2. Please quantify the expected heat rate impact of the intelligent soot blower system.

Not Applicable

iii. If the technology is not technically feasible or is limited, then please provide a detailed explanation of why the technology is not technically feasible or is limited due to the unique characteristics of each unit.

Not Applicable

c) **Please provide any other information relevant to DEQ's analysis of this candidate technology.**

Neural Network (NN) technology was developed and applied on a "test" basis to some steam generator equipment at other AEP units a decade ago. Reported results of the very controlled tests were highly variable and the technology focused on mainly one aspect (fuel-air distribution within the furnace) of the steam generation process Testers concluded that the technology did not provide sufficient economic benefit to apply at full scale Since that time, the implementation of the Mercury and Air Toxics Standards (MATS) rule has introduced increased regularity into the inspection, repair, and tuning of combustion controls. In addition, NN technology still requires manual coordination of several other processes, including starting and stopping large equipment such as pulverizers and fans, in order to maintain combustion stability within the steam generator. SWEPCO relies on well-trained and highly knowledgeable operators to perform this integrated control in a highly efficient and reliable manner without the use of NN's. The current use of the sootblowing system on Flint Creek Unit 1 maintains a high level of steam generator cleanliness and no measureable additive heat rate improvement is anticipated to result from integrating a neural network for this unit.

2)**Boiler Feed Pumps:**

Large electric motor powered boiler feed pumps (BFPs) supply feedwater to the steam generator in some units, and are responsible for a large portion of the auxiliary power consumed within a power plant (up to 10 MW from a 500 MW unit). Rigorous maintenance is required to ensure reliability and efficiency are maintained. Wear reduces the efficiency of the pump operations and requires regular rebuilds/upgrades/overhauls. These improvements for electric boiler feedwater pumps reduce auxiliary power demands and improve *net* heat rate, but would not result in measureable improvements in *gross* heat rate

At Flint Creek Unit 1 the main boiler feed pump is driven by a steam turbine and not by an electric motor. As such, for most of the operating range of Unit 1 (above 24% output), the boiler feed pump is self-regulating and matches the steam needed to the load at which the unit is operating In addition, it enhances the overall efficiency of the unit because of the reduced auxiliary electric demand (a reduction of as much as 35% of typical auxiliary load). For startup and low load operation, where there is insufficient steam yet available to supply the auxiliary drive steam turbine, a smaller motor-driven feed pump is used to provide the required feedwater. This pump is initially used during unit startup prior to the electric generator producing any output and is removed from service at approximately 24% load Boiler feed pump turbines can experience degradation and wear over time, and require periodic maintenance to repair turbine blades, exchange rotors, and restore steam seals. At Flint Creek Unit 1, a regular turbine overhaul is planned approximately every 10 years, or after 80,000-100,000 hours of service. Given that the original design of this unit includes a more efficient technology for use above startup flow conditions, and the operator has adopted a regular schedule for overhauls of the pump and turbine, it is reasonable to conclude that no incremental improvement is currently achievable.

a) Over the past year, how does the performance of the boiler feed pumps for each unit compare to the manufacturer specifications?

The pump design is highly efficient and robust to withstand the rigor of numerous years of continued service with very little O&M required. The pump also maintains its efficient performance for the duration of the period between overhauls. During the past year, the feed pump has performed within the design specifications.

b) When was the last time the boiler feed pump(s) for each unit was overhauled or upgraded?

The main turbine-driven boiler feed pump was last overhauled and rebuilt in 2016 The startup motor-driven feed pump was last overhauled in 2017.

c) If the boiler feed pumps have not been overhauled or upgraded in the period or at the performance characteristics recommended by the manufacturer specifications,

i. Please quantify the cost to overhaul or upgrade the boiler feed pump(s) for your unit.

Not applicable. The last overhauls were within specifications and within the performance period

ii. Please quantify the expected heat rate impact of overhauling or upgrading the boiler feed pump(s).

Not applicable. Maintenance overhauls are performed on the feed pumps in order to maintain their capacity to perform reliably and uninterrupted during the operating periods. Any degradation is unlikely to achieve the amount that is projected within Table 1 of the ACE Rule. The internal condition of the pump must be maintained within manufacturer's specification in order to avoid operational failure and a forced outage

iii. Please provide any other information relevant to the DEQ's analysis of this candidate technology.

Subcritical units using a single 1x100% capacity pump are not commonplace in the industry and thus the OEMs do not offer much in the way of efficiency improvements AEP is not aware of any advanced designs for a steam-driven or electric motor driven boiler feed pump that could provide a heat rate improvement of 0 2%-0.5% above this unit's current performance as set forth in Table 1 of the ACE Rule

d) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit

The boiler feed pumps at this unit have been regularly maintained in accordance with manufacturer's specifications and additional overhauls are unnecessary

3) <u>Please specify whether the air pre-heater for each unit listed above is regenerative (rotary) or recuperative (tubular or plate)</u>.

The two (2) air pre-heaters installed on Flint Creek Unit 1 are tri-sector regenerative air heaters which do rotate

a) If your unit has a regenerative air pre-heater, when were the seals last replaced?

The air heater seals were last replaced as a complete set in 2005 during a scheduled outage. Seals are inspected and maintained on an annual basis during maintenance outages as recommended by the air heater OEM. This maintenance can include repairs to sealing components or replacement of partial sets of seals as necessary, based on damage or wear

b) If the seals have not been replaced in the period or at the performance characteristics recommended by the manufacturer specifications,

i. Please quantify the cost to replace the seals for the regenerative air pre-heater for your unit

As discussed above, the seals are inspected and maintained in accordance with the manufacturer's recommendations during regular outages The costs for these inspections and repairs have not been separately tracked

ii. Please quantify the expected heat-rate impact of from replacing the seals.

The impact is very marginal since only partial set repairs or replacement are typically necessary due to extent of damage or wear Continued replacements in accordance with past practice will allow the unit to maintain its historic efficiency.

c) Please provide any other information relevant to DEQ's analysis of this candidate technology.

The improvement projected from this technique (upgraded air heater seals) results from limiting air in-leakage on regenerative air heaters by replacing air heater seals with newer designed low-leakage seals Most units have some rate of air in-leakage, which can result in higher demand on the fans that provide air to the combustion zone in the boiler and higher auxiliary power demands

For this unit, air heater seals are typically inspected, repaired or replaced with in-kind seals during equipment outages when the air heater baskets are replaced or when seals are found damaged Additionally, the air heater internal ducts and sector plates are inspected during maintenance on the air heater, and localized repairs and stationary seal replacements can be made during those inspections if materials are available, or included in future outage plans

There are products on the market that advertise lowering the amount of leakage experienced within air pre-heater equipment. While it is likely feasible to install such products on Flint Creek Unit 1, it is currently AEP's opinion that the newer designs for low-leakage seals present risks to unit reliability and air heater functionality that may outweigh any efficiency gains. A thorough technical review is needed to determine applicability and potential benefits for Flint Creek Unit 1. Plant operators currently use PI system screens for monitoring differential pressure, temperatures and flue gas pressure in the air heater and motor amps for the PA, FD and ID fans in order to assess air heater loading and performance Application of the low-leakage seal design would require some level of detailed engineering and design by the boiler and/or air heater OEM(s) to determine a suitable method of application and to determine the potential benefits to be gained and reliability risks to consider in each specific case. A feasibility study has not been performed for this unit. Some leakage at this location is necessary to avoid air heaters "locking up" (not being able to rotate) which can lead to malfunctions, curtailments, or availability problems.

d) Please provide a detailed explanation if the technology or practice is not technically feasible or limited due to the unique characteristics of the unit.

See response to item c) above.

4) <u>Variable Frequency Drives (VFD) information for each listed unit:</u>

Variable Frequency Drives are available that work in concert with traditional electric motors to vary the speed necessary during unit load changes to maximize performance of the driven equipment and reduce losses This results in a reduction of power consumption as an auxiliary load and helps to maximize the net electrical generation from the unit. The most effective applications are for electric driven boiler feed pumps that control feed water flow and induced draft fans that control air/gas flow through the flue gas path.

At Flint Creek Unit 1, approximately 50 - 60 percent of the electric demand on a typical unit has already been addressed, including both of the major applications for VFDs identified in the ACE rule First, the main BFP is driven by an auxiliary steam turbine that automatically adjusts to the required load and does not consume electricity. This pump/turbine combination is placed in service when the unit advances off of the startup system and achieves approximately 24% output and remains in service up through full load. Second, induced draft fans were last replaced on the unit in 2016 and are axial flow fans with variable blade vane pitch, which reduce energy losses, enhance operator control, and increase volumetric flow through the unit to increase efficiency The axial vane fans deliver substantially similar benefits as VFDs. In fact, in its 2009 report on coal-fired power plant heat rate reductions, Sargent & Lundy compared the benefits of centrifugal fans with VFDs to axial vane fans, and determined that the axial vane fans provided slightly superior performance *Coal-Fired Power Plant Heat Rate Reductions*, Sargent & Lundy, Final Report on Project 12301-001 (Jan. 22, 2009) at p 8-5.

a) **Does your unit have VFD controls for the induced draft (ID) fans**?

No

i. If so,

1. When was the VFD first operated?

Not Applicable

2. What impact did this have on your heat rate during base-load and cycling operating scenarios?

Not Applicable

ii. If not,

1. Please quantify the cost to install and operate a VFD for the ID fans for your unit.

As mentioned in the paragraph above, Flint Creek Unit 1 was able to install axial vane variable flow fans for the induced draft fan applications when the FGD equipment was installed in 2016. SWEPCO does not have a true cost for adding a VFD onto an existing induced draft centrifugal fan The axial vane fans were part of the larger FGD equipment project installed in 2016. Power differential to operate the axial vane fans versus a conventional centrifugal fan and motor with VFD is negligible.

2. Please quantify the expected heat-rate impact of the installation and operation of VFD for ID fans for both base-load and cycling operating scenarios.

Based on the Sargent & Lundy report, SWEPCO anticipates that any difference would be negligible

b) **Does your unit have VFD controls for the boiler feed pumps?**

No. As mentioned in Question 2 (Boiler Feed Pumps) above, the single main boiler feed pump is driven by a steam turbine. The auxiliary startup boiler feed pump is driven by an electric motor

i. If so,

1. When was the VFD first operated?

Not applicable

2. What impact did this have on your heat rate during base-load and cycling operating scenarios?

Not applicable

ii. If not,

1. Please quantify the cost to install and operate a VFD for the boiler

feed pump(s) for your unit.

Application of a VFD to the auxiliary boiler feed pump drive motor would likely be cost prohibitive since the motor is approximately 5,000 HP, operates for a limited time only during startup when feed water flow is low and controlled by a regulating valve and the electric generator is not yet connected to the grid (producing 0 MWs) Occasionally the auxiliary feed pump may be brought into service during unit load reduction with the generator producing low MWs for shorts periods of time (hours) to perform troubleshooting or testing of the main BFP or drive turbine. This period would likely not be part of the emissions performance standard period of testing.

2. Please quantify the expected heat rate impact of the installation and operation of VFD for the boiler feed pump(s) for both base-load and cycling operating scenarios.

The impact of adopting a VFD to the auxiliary boiler feed pump motor would be extremely low, well below the suggested range offered in ACE Rule Table 1, as this motor is infrequently used and likely produce unmeasurable benefits.

iii. Please provide any other information relevant to DEQ's analysis of this candidate technology.

Because there is no electrical load consumed by the boiler feed pump over the majority of this unit's operating range (all loads above 24%), the design of the axial vane fans provide similar efficiency benefits, and the small motor used during start up operates only at low loads and infrequently, any benefits from applying VFDs would be well outside the range estimated by EPA and would not be cost-justified.

c) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit

See response to item b)iii., above.

5) <u>Blade Path Upgrade (Steam Turbine) for each listed unit:</u>

The best candidates for blade path upgrades are those turbines experiencing steam leaks and blade erosion, where efficiency improvements can be achieved using computerized flow modeling and innovative materials. However, there is significant variation among units. These upgrades are large capital investments and require long lead times

Flint Creek Unit 1 is equipped with one combined and opposed-flow high pressure/reheat turbine and two low pressure turbines This unit is unique on the AEP system. No spare turbine rotors exist so all components are either repaired or replaced if necessary during maintenance inspections.

a) Has the steam turbine for the unit been upgraded or overhauled in the past ten years? If so,

i. When was the turbine upgraded or overhauled?

The steam turbine on Flint Creek Unit 1 has not been upgraded in the last 10 years. The steam turbine has been overhauled during the last 10 years. Steam turbine sections (HP/RH, LP1, LP2) were all overhauled last in 2018.

ii. Describe how the turbine was upgraded or overhauled.

During the 2018 unit maintenance outage, the turbines were overhauled by opening and assessing condition, cleaning and removal of blade deposits, inspection and non-destructive testing of components, repairing or replacement of worn or damaged blades with like-kind materials and restoration of seals to design clearance values. Specifically, inlet row rotating blades were replaced with new in the HP turbine (Row 1) and RH turbine (Row 8). Closing clearances were recorded and the turbine casings reassembled. Rotor vibration levels are monitored during startup to determine no rubs occur and rotor balance is acceptable. Steam pressures and temperatures are measured to confirm proper steam expansion is taking place.

iii. How did the upgrade or overhaul impact the unit's heat rate?

As a result of the turbine overhaul, most of the "recoverable" losses that occur during the normal operating cycle of the steam turbine sections were reduced and overall performance moved closer to design values A formal heat rate test utilizing highly calibrated test instruments is not typically performed following a turbine overhaul as this is not cost effective. Improvement is typically measured with installed station instrumentation by a reduction in feedwater flow and steam generator heat input for a given MW production as corrected to standard throttle conditions.

iv. Are there further upgrades available that would improve the efficiency of the turbine?

Yes, there are steam path upgrades that have been applied to similar units. Typically a steam path upgrade is only cost-justified if other changes to a unit will significantly increase auxiliary loads, and some of those losses can be offset by the turbine upgrade. The novel scrubber design used at Flint Creek Unit 1 does not increase auxiliary power demands as much as conventional wet or dry scrubbers, so the investment was not justified when those controls were installed Currently, demand for electricity is not growing at a rapid pace, and other alternatives for additional generating capacity can be more economically attractive than increasing the output of a coal-fired unit. An economic evaluation for any potential steam path upgrade is recommended. These factors, and the potential to trigger NSR review, would need to be carefully considered in addition to whether a turbine upgrade would fall within the range of the ACE Rule Table 1 estimates as well as the Table 2 range for HR improvement.

b) If not,

i. Please quantify the cost to upgrade or overhaul the steam turbine for your unit. (You may factor the costs associated with new source review, if it would be triggered by the upgrade, into your cost calculations.)

The cost of a turbine overhaul or upgrade can vary significantly based on the amount of damage to or degradation of existing components (for an overhaul), or the extent of any design changes associated with an upgrade . Some upgrades may require replacement of turbine rotors, blade carriers and casings in addition to the blades, at a substantially increased cost and scope of work No specific upgrades have been designed or estimated for the turbines at Flint Creek Unit 1.

ii. Please quantify the expected heat rate impact of upgrading or overhauling the steam turbine.

Regular overhauls restore and maintain the efficiency of the unit. No specific upgrade designs have been developed for Flint Creek Unit 1 and therefore the heat rate impact cannot be estimated.

c) Please provide any other information relevant to DEQ's analysis of this candidate technology.

Steam turbine overhauls and steam path inspections/repairs have been performed at Flint Creek Unit 1 over the years to return the turbine to near design conditions These were performed during scheduled outages when turbine inspections have allowed for any liabilities to be addressed and for replacement parts to be procured and made ready for installation. Current upgrade offerings that may be available for the turbine sections have not been deemed cost-effective. The next regular maintenance opportunity for this turbine is not until 2028 at the earliest.

d) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.

Please see the responses to items b) and c), above.

6) <u>Economizer for each listed unit</u>

Replacing or redesigning the economizer can optimize temperatures at the exit of the boiler. Boiler layout and construction may limit the applicability of this measure to certain units

a) When was the economizer last replaced?

The economizer on Flint Creek Unit 1 is original and has never been replaced. On occasion, there has been a need to locate and access certain areas of the economizer to address leaking tubes or other physical damage. This repair could result in replacement of a small number of tubes or partial tube sections but no major replacement of tube bundles has been necessary.

b) Throughout the past year, how does the performance of the economizer for each unit compare to the manufacturer specifications for a new unit?

During the past year, the economizer on Flint Creek Unit 1 has performed well, allowing for critical temperatures such as boiler exit gas and air heater gas outlet temperatures to remain within manufacturer specifications throughout the load range

c) If the performance of the economizer for a unit has degraded outside the performance range of the manufacturer's specifications:

i. Please quantify the cost to redesign/replace the economizer for your unit.

Not applicable

ii. Please quantify the expected heat-rate impact of redesigning/replacing the economizer.

Not applicable

d) Please provide any other information relevant to DEQ's analysis of this candidate technology.

Because there are currently no issues with the performance of the existing economizer, and no specific design changes have been identified that would allow the unit to increase efficiency without potentially compromising the operation of downstream equipment, there are no known changes to evaluate, and no heat rate improvement is anticipated to be associated with an economizer redesign/replacement project.

e) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.

It is technically feasible to replace an economizer either with like-kind design or with some improvements in materials or heat transfer characteristics. Limited like-kind replacements of economizer sections have been made to repair tube damage with no impact to the heat rate of the unit However, making changes to the economizer design or replacing the economizer in its entirety would have significant impacts on downstream equipment at this unit, including the air heaters, which are sensitive to flue gas temperature changes. The existing economizer is functioning well in its current cycle and condition and does not warrant replacement.

7) <u>Heat Rate Improvement Practices</u>:

a) Do the staff at the plant where the unit is located undergo routine training that would positively affect the heat rate of the unit or units? (Such training may include any training related to efficiency or any other training on practices that result in heat rate improvements.)

Heat rate improvement "awareness training" is suggested as a means of elevating awareness of specific heat rate improvement efficiency measures among the operations and maintenance staff at units including Flint Creek Plant affected by the rule. In the response to ACE Rule comments, EPA recognized that the level of awareness at individual units could vary dramatically, and that states might simply take into consideration whether there are existing programs at specific units as part of the overall evaluation of the candidate technologies Capital costs are anticipated to be minimal and the impact of implementing new or existing programs is difficult to estimate and expected to be widely variable.

As generating units across the country have joined regional transmission organizations and begun offering the output of their units into competitive generation markets, cost-effective operation of individual units has become increasingly important. AEP units in the west are dispatched as part of SPP (Southwest Power Pool) which has a robust day-ahead energy market. As a result, increasing attention has been focused on ways to improve efficiency and lower operating costs.

i. **If so, describe the training program including frequency of training and practices taught.**

AEP provides training, monitoring tools, and "best practice" sharing forums for its employees as a way to help plant operators and staff to improve their awareness and equip them with means to maintain efficient operations and identify further efficiency improvements Some of these tools and practices include:

- Operator training
- HRI classes, focusing on plant system optimization, are held at the Generation unit simulator center in St. Albans, WV and periodically attended by SWEPCO / Flint Creek personnel
- An automated Monitoring & Diagnostics Center
- Equipment control systems capable of automatically responding to changing conditions
- Regular technology updates and reviews
- Participating in and contributing to AEP Operational Excellence Program for best practices, including maximizing performance and reducing heat rate
- Maintaining thermal performance models of the unit design cycle with equipment references

The degree to which individual unit operators, supervisors and engineers undergo various parts of this training depends upon their position and desire to further develop and take on additional responsibilities Some positions such as a Control Center Operator (CCO) requires prior successful completion of the NUS Heat Rate course. The CCO is also responsible to monitor "controllable" heat rate monitor screens in the unit control room to aid in determining the most efficient unit operation conditions for Flint Creek Plant.

ii. If not,

1. Please provide to DEQ a plan for instituting such a program.

Not applicable since AEP already conducts such a program for Flint Creek operators

2. Quantify the annual costs of implementing a program.

Not available on a specific unit or plant basis as this is part of continual learning within the AEP System

3. Quantify the expected heat-rate impacts of implementing a program.

Existing programs and measures are currently being employed and improvements are reflected in the historic emissions data for this unit. The precise percentage in unknown. No quantifiable incremental increase in heat rate improvement is anticipated as a result of continuing the existing practices, which include regular technology reviews and updates

b) EPA requires DEQ to consider an "on-site appraisal" of heat-rate improvement opportunities at a specific unit. Please submit a report detailing the results of an onsite appraisal of heat-rate improvement opportunities. This appraisal may be conducted by an internal group or a third-party. Include a summary of the most recent inspection and recommendations for equipment maintenance or replacement to minimize heat-rate deviations, and include actions taken in response to the recommendations.

The practices identified in the prior section are tools used to assist unit operators and engineering support personnel on the AEP system in planning regular maintenance, developing the scope of work for planned outages, and designing monitoring or information collection efforts tied to specific equipment issues or unit liabilities. This can in turn allow internal personnel or third parties to be engaged to perform a more in-depth evaluation and assessment of specific ideas for improved heat rate performance. Such "appraisals" can be conducted to address issues identified on individual units, or to develop a more comprehensive effort that could be implemented at multiple units with a strategic alignment Several ideas in the past were identified as potential heat rate improvements and collaboratively reviewed between plant staff, M&D Center analysts, AEP Engineering and in some cases an equipment OEM. These performance "enhancements" were developed with the intent of lowering pressure drop or stopping undesirable steam leakage flow as a means to improve performance and lower heat rate Power plant personnel and engineers continually review the performance of various pieces of equipment to look for opportunities to make improvements, solicit necessary funding and outage time, and procure the necessary materials to implement the improvement Many of these improvements are small and hard to measure individually or at the specific time of change, but continually aid in allowing the unit to perform as efficiently as possible. An example of these types of efforts include AEP's engagement of internal engineering resources or third party computerized flow modeling expertise to address optimization of low NOx burner combustion and over-fire air controls. Current internal efforts are focused on optimizing unit operations at partial loads, or during sustained periods of low-load operation as being dictated by the SPP-controlled marketplace.

c) Does your plant have a routine steam surface condenser cleaning program?

Improved steam surface condenser tube cleaning was selected as a HRI measure that forms part of the BSER by EPA because the efficiency with which steam is condensed back into liquid is a critical part of the thermodynamic cycle Lowering the temperature in the condenser and having an effective air removal system in operation decreases backpressure on the turbine allowing more efficient expansion in the steam cycle

Flint Creek Unit 1 main condenser undergoes an annual inspection and cleaning of the tubes each spring The steam side of the tubes are inspected via physically entering the condenser steam compartment and looking at tube cleanliness and removing any debris. The water side of the condenser tubes are cleaned continually through the use of a system which circulates cleaning balls randomly through the condenser tubes while the unit is in service to prevent deposition on the tubes

i. If so, describe the impact that this program has on the heat rate of each unit.

Condenser fouling has not typically been a problem on Flint Creek Unit 1. Performance as indicated by the relationship between cooling water temperature and back pressure achieved during seasonal periods has tracked close to design. It is apparent that the cleaning methods are working and the quality of the cooling water and steam purity in the condensate cycle are being managed at optimum values.

ii. If not,

1. Please provide to DEQ a plan for instituting such a program.

Not applicable

2. **Quantify the annual costs of implementing a program**

3. **Quantify the expected heat-rate impacts of implementing a program.**

d) **Please provide a detailed explanation if a practice is not technically feasible or limited due to the unique characteristics of the unit.**

Not applicable

e) **Please provide any other information relevant to the State's analysis of these practices.**

Continuous monitoring of condenser performance for Flint Creek Unit 1 indicates that control parameters regarding water quality and tube pluggage ratio are within acceptable limits. The condensers are performing well throughout the load range and under a variety of seasonal temperature conditions Thus there is no basis to consider any changes regarding condenser cleaning procedures for this unit.

8) Gross vs net generation standards

a) Would you recommend the standards of performance for each affected unit be established in pounds of carbon dioxide emitted per net megawatt hour or per gross megawatt hour? Explain your recommendation.

The performance standard should be based on gross generation as this is the total generation produced by the unit, and is currently regularly monitored and reported through the Clean Air Markets Division for all units.

b) If your recommendation is for a gross generation-based standard, then do you have any recommendations for accounting for emissions reductions attributable to technologies affecting only net efficiency?

Technologies that impact net efficiency can be transient (impacting only certain load ranges or operating conditions) and difficult to measure Gross measurements will assure that all conditions and load ranges are adequately measured and reported and there is no requirement to separately account for potential improvements in net efficiency.

AMERICAN ELECTRIC POWER

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May 1, 2020

Mr. William Montgomery
Associate Director
Office of Air Quality
Division of Environmental Quality
Department of Energy and Environment
5301 Northshore Drive
North Little Rock, AR 72118

Dear Mr. Montgomery:

Enclosed is a set of narrative responses that provides the information requested in your letter dated April 16, 2020, to Brian Bond at Southwestern Electric Power Company (SWEPCO). The information is provided to support your office's efforts to develop source-specific standards pursuant to the emission guidelines contained in the Affordable Clean Energy (ACE) and supplements the responses provided in our letter dated March 20, 2020. Certain of the information contained in the responses and attachments is confidential business information that is protected from disclosure internally and not publicly disseminated without a request to protect the information from public disclosure. The complete set of responses and attachments is being submitted in a sealed envelope and has been marked "Confidential Information" on the face of the documents themselves, and on the envelope.

We also are enclosing a "public version" of this information, and an affidavit executed by Scott A. Weaver that contains the information required under Reg. 18.1402(A)(1) and (2) to support our request that the information redacted from the "public version" be treated as confidential business information and not be disseminated or disclosed to the public.

If you have any questions concerning this information, please direct them to Mr. Weaver at (614) 716-3771 or by email at saweaver@aep.com. Thank you for your assistance.

Sincerely,

/s/ Janet J. Henry

Janet J. Henry
Deputy General Counsel

RESPONSES OF SOUTHWESTERN ELECTRIC POWER COMPANY TO ARKANSAS DIVISION OF ENVIRONMENTAL QUALITY REQUESTS DATED APRIL 16, 2020

Public Version

1. *Neural Network/Intelligent Sootblower System Information:*
    a. *In your March 16, 2020 letters, you indicate that both Flint Creek Unit 1 and John W. Turk Unit 1 were not tied into a neural network, but that this candidate technology is technically feasible. The letters indicated that these units were monitored by a centralized Monitoring and Diagnostic Center (MDC), which provides real-time data, spots early trends, and recommends actions to improve performance or eliminate a curtailment before damage occurs. In our March 24, 2020 meeting, you indicated that the MDC system was functionally equivalent to a neural network system. Please compare and contrast the functionality and impacts on heat rate performance of the MDC system and a neural network system. Explain why installing a neural network system would not yield further heat rate improvements for either unit.*

RESPONSE:

In the ACE Rule, a neural network is defined as a computer model that can be used to optimize combustion conditions, steam temperatures, and air pollution controls at a steam generating unit. A number of computerized systems have been developed and marketed by vendors, each of which contains a specific suite of sensors and monitors, and each of which is designed to work with specific modeling software based on the fundamental engineering principles that apply to the combustion or steam conditions at that particular unit, and the specific air pollution controls that have been installed at the unit.

Both Flint Creek Unit 1 and the John W. Turk, Jr. Unit 1 are equipped with Process Information (PI) monitoring systems and Distributed Control Systems (DCS) that rely on the same types of monitors and sensors included in most Neural Network packages. Each unit typically has over a hundred different measures from various systems and equipment across the unit. These include primary and secondary air flows and temperatures, air and gas pressures and flows, pressure differentials for certain critical equipment, auxiliary loads, feedwater flow, fan speeds and pitch, and other measurements. Subsystems that are monitored and evaluated include the air heaters, pulverizers, burners, fans, dampers, feedwater heaters, reheaters, economizers, superheaters, boiler feed pumps, turbines, generators, air pollution control equipment, condenser systems, and electrical systems.

A neural network installation collects and evaluates the information from sensors installed on a single unit or small group of units at a single location, and recommends adjustments, triggers alarms or other notifications to the unit operators, or automates certain functions through the computer tracking and predictive software. Operators can respond and make adjustments as appropriate, investigate unusual conditions, or enter work orders into the plant maintenance system.

Southwestern Electric Power Company (SWEPCO) is one of six operating subsidiaries in the American Electric Power (AEP) system that own and operate fossil fueled-units. The AEP system includes over 31,000 MW of generating capacity, over 5,200 MW of which is renewable energy capacity. AEP companies operate approximately 13,000 MW of coal-fired capacity. Among the coal-fired units on the AEP system, there are several "series" of like-sized units of similar design. In the case of the SWEPCO coal-fired units, Turk is the only ultra-supercritical unit, but Flint Creek is similar in capacity and basic design to SWEPCO's two Welsh Units in Pittsburg, Texas.

The similarities in size and design of the various AEP series of units have made information sharing and performance tracking a hallmark of AEP's culture. In the 1970s, AEP developed a training center for unit operators, and equipped it with a generator simulator that mimicked the real experience of manning the unit controls at one of the system's plants. This in turn led to the creation of a centralized Monitoring & Diagnostics Center (MDC) in 2014, co-located with the training center in St. Albans, West Virginia.

At the MDC, thousands of instrument readings from the majority of the AEP fossil fleet are gathered and monitored. The information comes directly from the PI and DCS systems in real time. Information about sensor conditions and status and data trending and evaluation through the use of pattern recognition software allow the center to notify plant personnel of the need to check, replace, or repair individual sensors, or take other actions to respond to abnormal operating conditions. The MDC has built numerous models around critical processes within the AEP units, and is able to communicate and collaborate with plant and system operators to investigate and remedy conditions before equipment damage occurs. In a sense, the MDC serves as a virtual fleet-wide neural network for AEP's fossil units.

One example of this successful collaboration occurred at Turk Plant in 2018. The plant noticed that during load increases and decreases several monitored parameters were straying outside of normal ranges. Water collection levels would increase sharply and superheat temperatures at the outlet manifold would decrease sharply. This suggested poor heat absorption in the furnace. Operations also noticed that Power Clean (the B&W intelligent sootblowing system that controls the soot blowers and hydro jets) was showing poor quality in the furnace area and was markedly different from previous years. In addition, the dampers that control gas flows in the boiler convection pass were operating very differently.

Both the plant and the MDC were observing these trends, and MDC used their program to trouble shoot the issues. Both teams suspected that decreased heat absorption was playing a role. The MDC also noted that the mass air flow through the boiler had also increased. The difference in gas damper positions on load increases and decreases contributed to the changes in superheat temperatures, increased attemperation, and increased feedwater flow. During the next outage of sufficient length, the plant worked on the hydro jets, brought B&W in to tune the Power Clean system, and worked with B&W and the regional engineering organization (REO) to begin additional monitoring to provide additional diagnostic data and determine if further tuning or other support is necessary.

Since the MDC was opened, a total of 148 issues have been detected and addressed at Turk, and 76 issues have been detected and addressed at Flint Creek, including issues related to sensors, air heaters, fans, pulverizers, burners, boiler tubes, dampers, and other systems. As of the end of March 2020, MDC has identified and addressed over 9500 issues across the AEP system.

The capabilities of the MDC are essentially equivalent to the capabilities of a neural network on an individual unit, but with several distinct advantages not present with third party systems. First, the centralized function at MDC reduces the personnel and expense that would be required to support neural networks on each individual unit. Second, the information collected on a broad range of units across the AEP system provides opportunities to analyze and trend a more robust data set than could be gathered from an individual unit. Third, the information collected from units within the same series and the evaluations performed for one of the units in that series can highlight developing issues and solutions that can be applied to the entire series before equipment damage occurs. And fourth, the MDC staff can develop diagnostic tools and software that is customized to an AEP series of units based on the wealth of information in their systems, without the expense and delays associated with engaging a third party contractor.

For all of these reasons, a commercial neural network would not collect additional data, provide better trending and evaluation, or take advantage of the broader universe of data available at the MDC, and therefore would not produce any detectable incremental heat rate improvement beyond the performance currently achievable using the operator training, monitoring, and capabilities of the MDC.

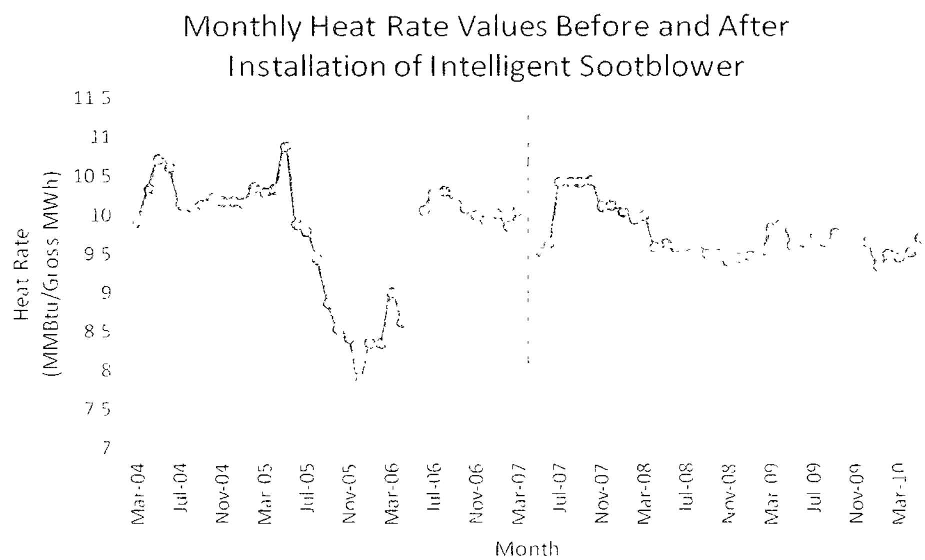
b. *In your March 16, 2020 letter, you indicated that Flint Creek Unit 1 is equipped with an intelligent soot blowing system installed in 2007.*
    i. *Please quantify the change in average heat rate and in heat rate variability associated with installation of this candidate technology based on the three years prior to installation and the three years after the installation. You may use Air Markets Program Data or any other historical data that SWEPCO may keep for its records.*

ii. Please report as a percentage rounded to the nearest tenth of a percent.

RESPONSE:

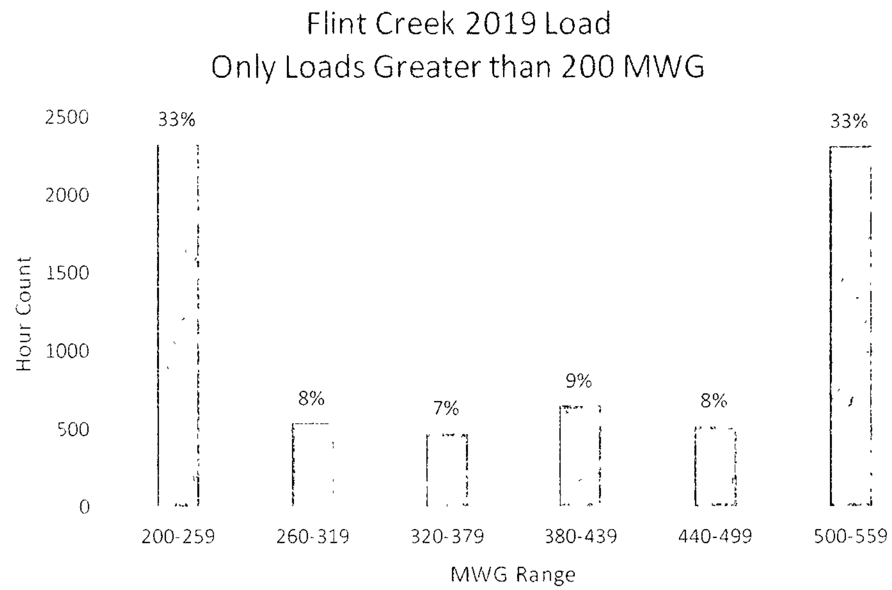
Due to the length of time that has passed since this equipment installation, there are no contemporaneous records of unit operating performance maintained by SWEPCO for the requested periods, and heat rate tests were not conducted prior to or after this installation.

Below is a chart of the calculated heat rates derived from reported Air Markets Program Data on a monthly basis during the three years prior to the sootblower system installation, and for the three years after the system was installed in April of 2007. As can be seen from this chart, there is significant variability on a monthly average basis before the project.



As discussed in comments AEP submitted on the Clean Power Plan (CPP), and the Affordable Clean Energy (ACE) Rule, the Air Markets Program Data reported for coal-fired units is highly variable due to both controllable and uncontrollable factors. The greatest variability is related to unit load, which is managed by the regional transmission organization, the Southwest Power Pool (SPP), in order to balance electrical supply and demand and secure reliable and reasonably priced electricity for customers. The two charts below show the distribution of operating hours at various unit loads in 2019, the most recent representative period of operation as part of SPP. There has been a significant increase in hours of operation at minimum sustainable loads to support the integration of intermittent renewable resources into the bulk electric system.

This results in a significant reduction in overall efficiency of operations, since heat rates at lower loads are much higher than those at full load.



MWG	# Hours	% Hours	Average Heat Rate
0-199	177	3%	
200-259	2333	33%	10.38
260-319	546	8%	10.08
320-379	482	7%	9.94
380-439	658	9%	9.85
440-499	530	8%	9.76
500-559	2318	33%	9.78
All	7044		

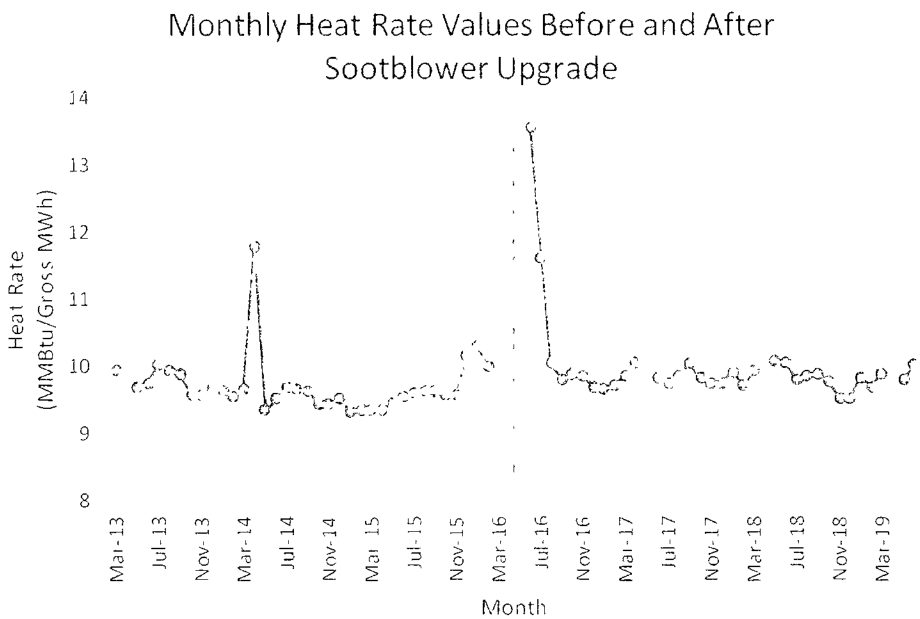
There is also significant seasonal variability due to the effect of ambient temperatures on unit operations, and the differences in circulating water temperatures during summer and winter. The number of unit start-ups, boiler cleaning during outages, and other factors also contribute to the variability. After the project, variability decreased but was still present based on these and other factors.

Prior to the installation of the intelligent sootblowing system, the three-year average heat rate for the unit was 9,740 Btu/kWh. After the project, the three-year average heat rate was 9,770 Btu/kWh. Based on this data, one might be tempted to conclude that heat rate did not improve, but was actually increased by 0.3% as a result of the project. However, if the three-year average heat rates are calculated on a calendar year basis rather than a 36-month block basis, the averages change, and the heat rate appears to improve rather than degrade. The heat rate during calendar years 2004-2006 was 9,750 Btu/kWh, and it was 9,680 Btu/kWh during calendar years 2008-2010, yielding a decrease in heat rate of 0.8%. Operational conditions, external factors, and unit load during these periods were likely responsible for the majority of the changes in heat rates, and no specific information is available to demonstrate what contribution, if any, the sootblowing system itself made to unit heat rates.

c) *In your March 16, 2020 letter, you also indicated that the intelligent soot blower system at Flint Creek was upgraded in 2016,*
   i. *Please quantify the change in average heat rate and in heat rate variability associated with upgrade of this candidate technology based on the three years prior to the upgrade and the three years after the upgrade. You may use Air Markets Program Data or any other historical data that SWEPCO may keep for its records.*
   ii. *Please report as a percentage rounded to the nearest tenth of a percent.*

The upgrade performed in 2016 affected both the computer software utilized to control the system, and added variable steam flow capability and additional sootblowers inside the furnace. As noted in our initial response, the system was designed to reduce the potential for unacceptable accumulations of slag within the furnace, and the heat rate penalty incurred when such slag formations reduce the heat transfer capability within the furnace.

The data reported to the Air Markets Program Data on a monthly basis during the three years prior to the software installation and for the three years after the system was installed in April of 2016 suggest that a much more significant change occurred after this upgrade. Based on the 36 months prior to and after the project, there is a 3.1% increase in heat rate, from 9,640 to 9,940 Btu/kWh. Using calendar year data instead of the 36 months immediately before and after the project, heat rates increase from 9,630 to 9,860 Btu/kWh, a 2.4% increase. The same uncontrollable sources of variability affect the data, and the primary outcome of this project was increased reliability in collection and processing of data, and better ash removal capabilities. However, no observable improvement is reflected in the Air Markets Program Data. The chart below is a graph of the data collected before and after the project.

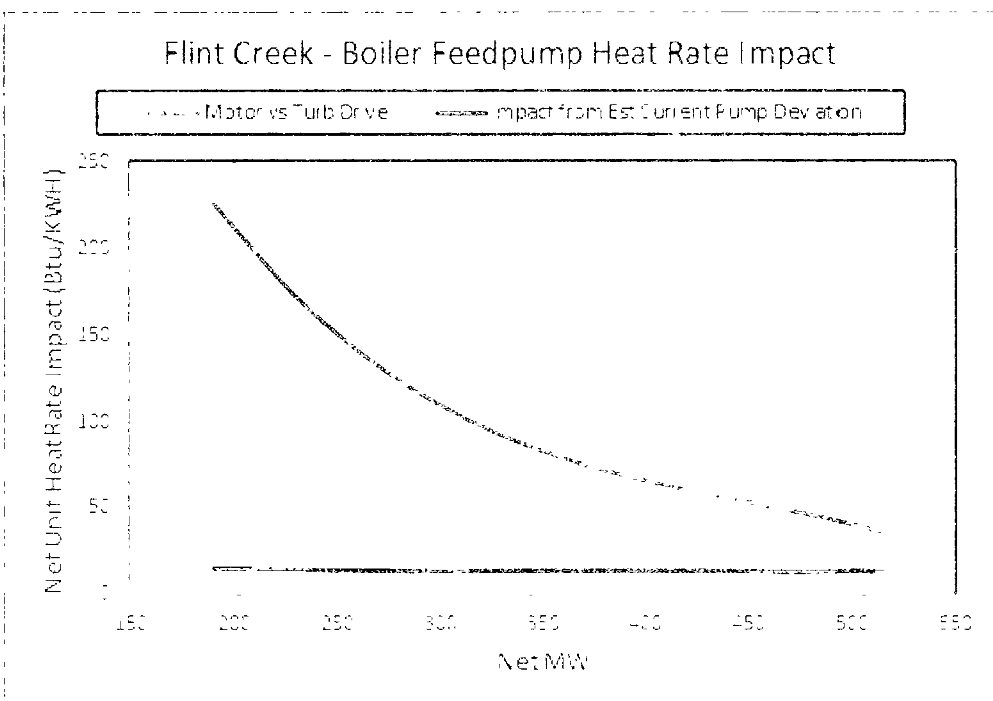


2) *Boiler Feed Pumps:*
   i) *In your March 16, 2020 letter, you indicated that the boiler feed pump for Flint Creek Unit 1 and John W. Turk Unit 1 performed within design specifications.*
   ii) *Please provide a summary of data from these units and compare this data to the design specifications to demonstrate this.*

As noted in our original response, the boiler feed pump at Flint Creek is fundamentally different in design than the technology upon which EPA's "best system of emission reduction" is based. Flint Creek has a single turbine-driven boiler feed pump rather than an electric motor-driven feed pump. The ability of the turbine-driven pump to adjust as needed across the operating range of the unit delivers both a significant savings in auxiliary load (up to 10 MW for a 500-MW unit like Flint Creek) and more efficient operation during load changes on the unit. At full load the boiler feed pump at Flint Creek Unit 1 is rated to deliver 9,126 gallons per minute (gpm) feedwater flow at 7,370 feet of head. Based on measurements of the feedwater flow and head delivered by the pump, Flint Creek boiler feed pump performance averages [redacted] below the design basis for this equipment between pump overhauls, and across all operating loads when the pump is in service. This means that there is an approximate [redacted] difference in performance, which is below the 20-50 Btu heat rate improvement EPA estimated would be achieved through extensive overhauls or replacements of boiler feed pumps. This pump was rebuilt in 2016 and is capable of delivering consistent and continued performance with regular inspections and overhauls.

The boiler feed pump at Turk is of similar design, and has consistently performed slightly better than its design basis during its first seven years of operation. On average, boiler feed pump performance at full load at Turk is [redacted] better than the design basis. The Turk boiler feed pump is designed to deliver 9,973 gpm at 11,197 feet of head. It, too, is capable of delivering consistent and continued performance with regular inspections and overhauls.

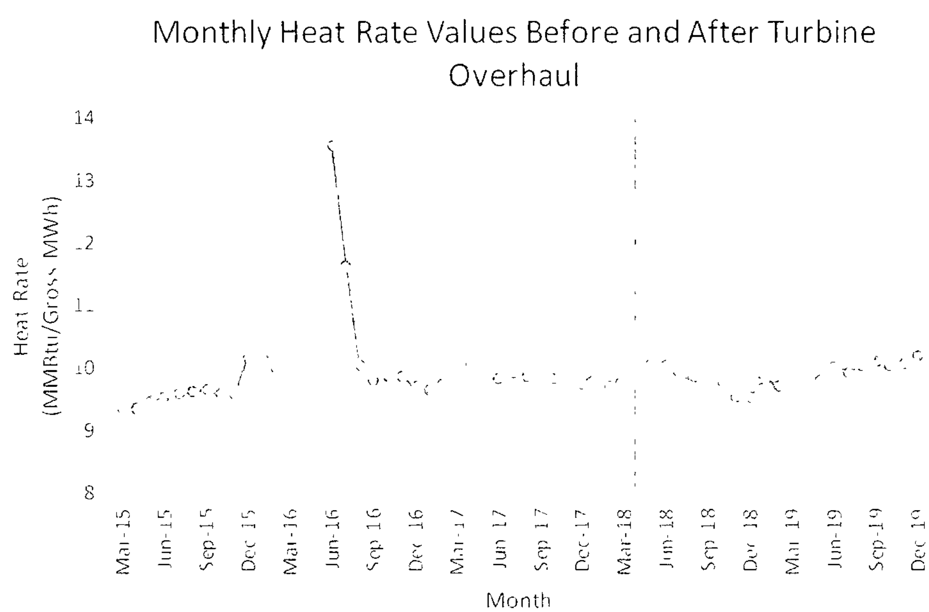
The graph below compares the efficiency of a newly rebuilt electric motor-driven boiler feed pump to the average performance of the boiler feed pump at Flint Creek Unit 1. The curve for the motor-driven pump represents the energy losses from the auxiliary power required to drive the pump.



If the performance of the motor-driven pump itself were degraded due to ordinary wear and tear, the entire curve would shift higher, and the difference in performance would be slightly greater than shown on the chart. The average performance at Flint Creek is sustainable with regular inspections and maintenance, and is superior to an electric motor-driven boiler feed pump at all operating conditions. Accordingly, no additional measures are necessary beyond the regular schedule of inspections and repair for this equipment.

3) *Blade Path Upgrade (Steam Turbine)*
   a) *In your March 16, 2020 letter, you indicated that the turbines at Flint Creek were overhauled in 2018.*
      i) *Please quantify the change in average heat rate and in heat rate variability associated with upgrade of this candidate technology based on the three years prior to the upgrade and 2019 data. You may use Air Markets Program Data or any other historical data that SWEPCO may keep for its records.*
      ii) *Please report as a percentage rounded to the nearest tenth of a percent.*

The chart below shows the monthly average heat rates for Flint Creek Unit 1 during the three-year period before the last overhaul in 2018, and after the unit returned to service through the end of 2019.



Once again, the data reported to the Air Markets Program Data on a monthly basis during the three years before the turbine overhaul and during 2019 after the turbine overhaul suggest different outcomes depending on the period that makes up the three-year average. Based on the 36 months prior to the project in April of 2018, as compared to May 2018 through December 2019, there is a 0.4% decrease in heat rate, from 9,910 to 9,870 Btu/kWh. Using calendar year data for the period 2015-2017 as compared to 2019 data, heat rates increase from 9,920 to 9,950 Btu/kWh, a 0.2% increase in heat rate.

b. *In your March 16, 2020 letter, you indicated that there are further upgrades available that could improve the efficiency of the turbines at Flint Creek Unit 1. The letter indicated that an economic evaluation for potential steam path upgrades is recommended. Please perform this evaluation and provide information responsive to the following:*
   i. *Please quantify the incremental cost of potential steam path upgrades rounded to the nearest dollar.*
   ii. *Please quantify the expected heat rate impact, as compared to the baseline, of potential steam path upgrades rounded to the nearest tenth of a percent.*

SWEPCO has identified a potential upgrade for the High Pressure and Intermediate Pressure (HP/IP) turbine. The existing turbine shell would be equipped with new rotors and buckets, new inner casings, new diaphragms, and new packing casings. The HP/IP turbine had its last overhaul in 2018, and the incremental improvement from the upgrade would be [redacted] based on the turbine's expected condition in 2023. Under ordinary circumstances, SWEPCO would not re-open the turbine for inspection and repair [redacted], and premature replacement of this equipment would not yield the full benefit assumed by EPA in its evaluation of the BSER.

SWEPCO obtained information from an original equipment manufacturer for these components in 2018, and has escalated the costs to 2023 dollars. The expected cost of the upgrade would be [redacted] including AFUDC and overhead.

Based on projections of future operations and fuel costs provided to ADEQ on a confidential basis, the project is not justified from an economic standpoint. The attached table submitted as CBI shows the projected annual fuel savings from the upgrade under projected operating conditions through the end of 2029, and [redacted].

Pursuant to a recent rate case settlement approved by the Arkansas Public Service Commission, SWEPCO is required to evaluate the retirement of Flint Creek Unit 1 by 2030. At the end of 2029, less than [redacted] would have been recovered through fuel savings, using favorable projections of future unit operations and stable fuel prices. Full recovery of the sunk costs would not occur [redacted] or later. Any reduction in capacity factors due to loss of load or introduction of more cost-effective generation resources within SPP would lengthen these periods substantially.

Given the unprecedented changes currently affecting the world in response to the pandemic, and competing needs for available capital, this evaluation is an appropriate benchmark for initial economic analysis. The attached spreadsheet shows the details underlying the analysis.

SWEPCO must seriously evaluate putting additional capital investments into facilities that may be considered for retirement due to the impact on customers and competing capital needs.

Flint Creek Turbine Upgrade Economic Evaluation **Public Version**

Cost HRI

HP/IP Upgrade

2023$

Projected Operation @ Flint Creek

Year	HEAT INPUT (GBTU)	TOTAL FUEL ($/MBTU)	Fuel Savings with Upgrade	
2020			$	
2021			$	
2022			$	
2023			$	
2024			$	
2025			$	
2026			$	
2027			$	
2028			$	
2029			$	$
2030			$	$
2031			$	$
2032			$	$
2033			$	
2034			$	
2035			$	